UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
999 18TH STREET - SUITE 300
DENVER, CO 80202-2466
Phone 800-227-8917
http://www.epa.gov/region08

Ref: 8P-W-GW

UNDERGROUND INJECTION CONTROL PROGRAM

FINAL PERMIT

Class I Non-Hazardous Waste Disposal Well

Permit No. CO10938-02115

Well Name: Suckla Farms #1

County & State: Weld, Colorado

issued to:

Wattenberg Disposal, LLC
1675 Broadway, Suite 2800
Denver, Colorado 80202

Date Prepared:

January 10, 2003

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
999 18TH STREET - SUITE 300
DENVER, CO 80202-2466
Phone 800-227-8917
http://www.epa.gov/region08

Ref: 8P-W-GW

UNDERGROUND INJECTION CONTROL PROGRAM

FINAL PERMIT

Class I Non-Hazardous Waste Disposal Well

Permit No. CO10938-02115

Well Name: Suckla Farms #1

County & State: Weld, Colorado

issued to:

Wattenberg Disposal, LLC
1675 Broadway, Suite 2800
Denver, Colorado 80202

Date Prepared:

TABLE OF CONTENTS

TABLE OF CONTENTS CONTINUED

TABLE OF CONTENTS CONTINUED

Issued this day of _________.

This permit shall become effective ___________.

Stephen S. Tuber
*Acting Assistant Regional Administrator
Office of Partnerships and
Regulatory Assistance

* NOTE: The person holding this title is referred to as the "Director" throughout this permit.

PART II. SPECIFIC PERMIT CONDITIONS

A. WELL CONSTRUCTION/CONVERSION REQUIREMENTS

1. Casing and Cementing. The construction details submitted with the application are hereby incorporated into this permit as **Appendix A** which graphically displays the details of the injection well under consideration. The construction shown in Appendix A is binding on the permittee.

2. Tubing and Packer Specifications. This well shall have a tubing and packer suitable for the proposed injection activity. The packer shall set on tubing and maintained at a location that is no more than 300 feet above the top most perforation at 9,276 feet.

3. Monitoring Devices. The primary method of monitoring shall be continuous pressure monitoring of the injection and casing tubing annulus pressure (at the wellhead) and continuous monitoring of the injection rate and volume. Prior to beginning Class I non-hazardous injection operation, the operator shall install and maintain in good operating condition the following equipment:

   (a) **Injection pressure**: a continuous pressure monitoring device in the injection tubing at the wellhead **shall be connected to either a continuous chart recorder with a resolution of at least 5 psi or a digital recording system with a sampling frequency of at least every 30 seconds**; and a one-half (½) inch Female Iron Pipe (FIP) fitting, isolated by plug or globe valves and located on the tubing to allow attachment of one-half (½) inch Male Iron Pipe (MIP) pressure gauges or the attachments for equivalent "quick-disconnect" pressure gauges certified for ninety-five (95) percent accuracy, or better, throughout the range of permitted operation in order to verify values for injection pressure being recorded from the continuous monitoring device.

   (b) **Wellhead pressure of the tubing/casing annular space**: a continuous pressure monitoring device in the wellhead casing/tubing annulus shall be **connected to either a continuous chart recorder with a resolution of at least 5 psi or a digital recording system with a sampling frequency of at least every 30 seconds**; and a one-half (½) inch Female Iron Pipe (FIP) fitting, isolated by plug or globe valves, and located on the tubing/casing annulus; and the above fittings shall be positioned to allow attachment of one-half (½) inch Male Iron Pipe (MIP) pressure gauges or the attachments for equivalent "quick-disconnect" pressure gauges certified for ninety-five (95) percent accuracy, or better, throughout the range of permitted operation in order to verify values for injection pressure being recorded from the continuous monitoring device.

The **tubing/casing annulus** shall be maintained full of either fresh water treated with a non-toxic corrosion inhibitor or other packer fluid as approved, in writing, by the Director. This fluid shall be **maintained under a positive pressure of between 100 and 200 psi.** A diesel freeze blanket or other fluid as approved, in writing, by the Director may be circulated from surface to below frost level at completion to prevent freezing and possible equipment failure during winter months.

(c) **Well shutdown**: the continuous monitoring system shall have automatic well shut down switches, such as a Murphy switch, installed which shall shut-in the well if either of the following occur:

(i) The surface injection (tubing) pressure shall be operated at pressures less than 3,700 psi. Any increase in pressure that exceeds 3,695 psi shall result in an immediate shut down of the injection pumps; or

(ii) Because the gas pressure will vary as a result of fluctuation in the injectate temperature, the tubing/casing annulus pressure shall be maintained between 100 and 200 psi. Any operation outside of this range shall result in an immediate shut down of the injection pumps. When adjusting the annulus fluid pressure, the operator shall use the target value of 150 psi;

(d) **Fluid volume and flow rate**: Flow meters (magnetic or turbine) and continuous recording devices, such as a chart recorder with an accuracy of 1 barrel per minute or a digital recording system with a sampling frequency of at least every 30 seconds shall be installed in the injection line immediately upstream of the wellhead to track and document disposal fluid flow rates, and total fluid volumes.

For a given injection rate, the injection pressure should remain relatively constant. Input flow volumes shall be cross checked against injection pressure records to identify any possible divergence in the injection pressure for a given flow rate. A drop in injection pressure without a corresponding reduction in input flow rate may indicate a possible casing, packer, or other failure; and

(e) **Fluid analysis**: the injection line shall be equipped with sampling ports and appropriate connections to facilitate periodic collection of fluid samples representative of the injection fluids for chemical analysis. **The sampling point shall be in an unobstructed portion of the injection line down stream from the tanks but prior to the injection pumps.**

4. Proposed Changes and Workovers. The permittee shall give advance notice as soon as possible to the Director of any planned physical alterations or additions to the permitted well. Major alterations or workovers of the permitted well shall meet all conditions as set forth in this permit. A major alteration/workover shall be considered any work performed, which affects casing, packer(s), or tubing.

The permittee shall provide all records of well workovers, logging, or other test data to EPA as part of the quarterly report for the period in which the activity was completed. **Appendix B** contains samples of the appropriate reporting forms.

Demonstration of mechanical integrity (tubing/casing annulus pressure test, **Appendix G**) shall be performed within thirty (30) days of completion of workovers/alterations and prior to resuming injection activities, in accordance with Part II, Section C. 2. (a) of the Permit.

5. Logging and Well Testing Specifications. The permittee shall give **at least two days**, advance notice to the Director of any planned logging or testing. This notice shall include a plan for conducting the proposed test or log. The test plan shall be developed using the Guidelines in Appendix I:

(a) After any workover that involves any remedial cementing of the casing, the operator shall run a new cement bond log (with a gamma ray, travel time curve, casing collar locator, amplitude curve, and variable density log) that covers the area of the cementing to verify the adequacy of the cement placement. This log will be run following the guidelines in **Appendix D**; and

(b) A pressure fall-off test is required for Class I operations [40 CFR § 146.13 (d) (1)] and **must be performed at least once every twelve months** for the purpose of monitoring pressure buildup in the injection zone in order to detect any significant loss of fluids due to fracturing in the injection and/or confining zone, and to aid in determining the lateral extent of the injection plume.

The initial yearly pressure falloff test shall take place **during the month of April 2004**. Any subsequent falloff tests shall be run within a one week period of the date of the initial falloff test The pressure fall-off tests shall involve injecting fluids at a constant rate for at least twenty-four (24) hours, or a sufficient period of time (which ever is greater) until the reservoir pressure reaches stability (radial flow conditions, as determined by a field evaluation of the raw data), followed immediately by a shut-in period of sufficient duration to establish a valid observation of a pressure fall-off curve.

The Operator shall develop a test plan for conducting the pressure falloff test. Appendix I contains a guideline for conducting pressure falloff tests that was developed by EPA Region VI for use in developing a site specific plan. The final test plan shall be submitted to Region VIII for review and approval, at least, 30 days prior to conducting the annual pressure falloff test.

The actual falloff test shall conform to the final falloff test plan approved by EPA. This test shall be considered complete when the pressure curve becomes asymptotic to a horizontal line as the reservoir reaches ambient pressure. The initial pressure buildup shall be performed with both a downhole quartz pressure gauge with an accuracy of 0.01 psi and surface monitoring equipment utilizing pressure monitoring devices with an accuracy of 0.01 psi to establish a correlation between surface and downhole measurements. It is important that the initial and subsequent tests follow the same test procedure, so that valid comparisons of reservoir pressure, permeability, and porosity can be made. At a minimum, subsequent tests shall be conducted with surface pressure monitoring devices with an accuracy of 0.01 psi. The Director may require the use of downhole quartz gages on any subsequent test, if deemed necessary. The permittee shall analyze test results and provide a report with an appropriate narrative interpretation of the test results, including an estimate of reservoir parameters, information on any reservoir boundaries, an estimate of the well skin effect, and reservoir flow conditions. **The report shall also compare the test results with the previous years test data and shall be prepared by a knowledgeable analyst.**

B. CORRECTIVE ACTION

The operator is not required to take any corrective action before the effective date of this Permit.

C. WELL OPERATION

1. Prior to Commencing Injection. Injection of Class I non-hazardous materials into the Suckla Farms # 1 is presently occurring under the authority of the existing Permit. Upon the effective date of this Permit, continued injection into the Suckla Farms # 1 is authorized **subject to the conditions herein**.

2. Mechanical Integrity.

   (a) Notification. The Permittee shall give at least two weeks, advance notice of any required integrity test. The Director may allow a shorter notification period if it would be sufficient to enable the EPA to witness the mechanical integrity test (MIT). Notification may be in the form of a yearly or quarterly schedule of planned mechanical integrity tests or it may be on an individual basis.

(b) Test Methods and Criteria. For Part I (internal) of mechanical integrity, test methods and criteria are to follow **current UIC Guidance for Conducting a Pressure Test to Determine if a Well has leaks in the Tubing, Casing or Packer (Appendix G)**. A well passes the mechanical integrity test for Part I if there is less than a ten (10) percent decrease or increase in pressure over the thirty (30) minute period. For Part II (external of mechanical integrity, test methods and criteria are to follow **current UIC Guidance for demonstrating the absence of significant flow into or between USDWs adjacent to the casing using either temperature surveys or a radioactive tracer survey (Appendix E and Appendix F).**

(c) Routine Demonstrations of Mechanical Integrity. The Permittee must demonstrate Part I and Part II of mechanical integrity by arranging and conducting a test at least once every five years. A tubing/casing annulus pressure test shall be conducted at the **maximum injection pressure or at least 1000 psig whichever is lesser (with a pressure differential of at least 200 psig between the annulus pressure and the injection tubing pressure)** to demonstrate Part I (no leaks in the tubing, casing or packer). This test shall be for a minimum of thirty (30) minutes with the well shut-in, and pressure values shall be recorded at five-minute intervals. The operator shall conduct either a temperature log or a radioactive tracer log to **demonstrate** Part II (no flow into or between USDWs adjacent to the casing). If necessary to demonstrate no flow adjacent to the casing, the Director may request that additional logs be conducted.

Also, Part I of mechanical integrity shall be successfully demonstrated **after workovers** (see Part II. A. 5. of the Permit). Results of the test shall be submitted (on EPA form found in **Appendix B**), with documentation, to the Director with the Quarterly Report for the period in which the activity was completed.

(d) Loss of Mechanical Integrity. If the well fails to demonstrate mechanical integrity during a test, or a loss of mechanical integrity as defined by 40 CFR § 146.8 becomes evident during operation, the permittee shall notify the Director in accordance with Part III, Section E. 10. (c) of this permit. Furthermore, injection activities shall be terminated immediately; and operations shall not be resumed until the permittee has taken necessary actions to restore integrity to the well and the Director gives approval to recommence injection.

3. <u>Injection Interval</u>. Injection zone shall be limited to the Lyons Sandstone in the interval from the depths of 9,276 feet and 9,418 feet. The injection zone is confined by a 300 foot interval of shales and interbedded siltstones that overlie the injection reservoir.

4. <u>Injection Pressure Limitation</u>. Based on the instantaneous shut-in pressure from a fracture treatment of the well, a **maximum surface injection pressure of 3,700 pounds per square inch gauge (psig)** has been established.

   (a) If a higher pressure is requested, it must be accompanied by a valid step-rate test (SRT) of the injection zone, using fluid normally injected, to determine both the instantaneous shut-in pressure (ISIP) and the formation breakdown pressure. The Director will determine the allowable pressure modification based upon the test results and other parameters reflecting actual injection operations.

   (b) **The permittee shall give thirty (30) days advance notice to the Director if an increase in injection pressure will be sought.** Details of the proposed test shall be submitted at least seven (7) days in advance of the proposed test date so that the Director has adequate time to review and approve the test procedures. Results of all tests shall be submitted to the Director within ten (10) days of the test. Any changes in the maximum injection pressure established by this section, as dictated by the test results, will be made as a minor modification to the Permit.

5. <u>Injection Volume Limitation</u>. Cumulative injection volume of oil field fluids, plus Class I non-hazardous waste fluid shall be **limited to 8,300,000 barrels** over the total life of the well. The injection rate is not limited, but in no instance shall the rate result in an injection pressure that exceed the limit established in Part II, Section C, item 3, above. When the maximum cumulative volume is reached, EPA will make a decision to extend the limits of the injection zone or to terminate the Permit.

6. <u>Injection Fluid Limitation</u>. The permittee is authorized to inject Class II oil and gas related fluids, Class I fluids from underground fuel storage tank (UST) cleanup sites that has been determined to be non-hazardous, and other non-hazardous industrial wastes as approved by the Director. Class II fluids are brought to the surface in connection with natural gas storage operations, or conventional oil and gas production and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection. Injection of any hazardous waste as identified by EPA under 40 CFR 261.3 is prohibited.

   The permittee has provided EPA with a current list of Class II sources (production wells), consisting of 212 pages (up to 44 wells per page), that have utilized the facility for disposal in the past. This list is part of the administrative record and the Permittee may accept fluids from wells presently on this list without further notification of EPA. **New additions** to this list in the Administrative record shall be made a binding part of this Permit following the procedures outlined below:

For new Class II and UST (conventional fuel and heating oil) fluid sources:

(a) The permittee shall submit a request for **disposal of fluids from any new Class II or UST source (associated with the storage of conventional engine fuel or heating oil), prior to acceptance of the fluid for disposal.** The request shall include the source name, location, operator, and a brief description of the operation that produced the source. If the source is an UST site, the discussion must provide information demonstrating that no metals above the TC toxicity characteristics are present in the fluid.

(b) The request shall be accompanied by a water analysis consisting of at least total dissolved solids content, pH, specific conductivity, and specific gravity.

(c) Any approval for injection may be granted verbally, with subsequent written approval from the Director.

For new UST (Other than conventional fuel and heating) or industrial non-hazardous fluid sources:

(a) The permittee shall submit a request for **disposal of fluids from any new source, prior to acceptance of the fluid for disposal.** The request shall include the source name, location, operator and a description of the operation that produced the waste fluid.

(b) The request shall include a complete analysis of the fluids, including cations, anions, BTEX, EP Corrosivity, EP Ignitability, EP Reactivity, and EP Toxicity using the Toxicity Characteristic leaching Procedure for all listed parameters.

(c) Any approval for injection may be granted verbally, with subsequent written approval from the Director.

7. Annular Fluid. The annulus between the tubing and the long string casing shall be filled with fresh water treated with a corrosion inhibitor or other packer fluid as approved, in writing, by the Director. The annulus shall be maintained under a positive pressure ranging from 100 to 200 pounds per square inch gauge (psig) with a target value of 150 psig.

D. MONITORING, RECORDKEEPING, AND REPORTING OF RESULTS

1. Injection Well Monitoring Program. Samples and measurements shall be representative of the monitored activity. The permittee shall utilize the applicable analytical methods described in Table 1 of 40 CFR § 136.3, or in Appendix III of 40 CFR Part 261, or in certain circumstances, by other methods that have been approved by the EPA Administrator. Monitoring shall consist of:

   (a) *Sampling and analysis of injection fluids.* Analysis of the injection fluids shall be performed as follows:

      (i) For fluids which may vary in composition, the analysis of **industrial waste fluids** shall be performed prior to delivery, or prior to being pumped from individual delivery trucks into on-site storage tanks. Fluid samples shall be analyzed for chemical, physical, biological, and radiological constituents, including cations and anions, pH, conductivity and total dissolved solids content. If however, the analyses of four (4) loads indicates the material is not hazardous and the quality has little variability, the Director may waive the

      requirement for analyzing every load. Subsequent to this waiver, a minimum of one load in five shall be analyzed.

      (ii) For fluids associated with a specific process which do not vary in chemical composition, the analysis of **industrial waste fluids** received at the well site shall be performed once every ten loads or once per month, which ever is less. Fluid samples shall be analyzed for chemical, physical, biological, and radiological constituents, including cations and anions, pH, conductivity, and total dissolved solids content. If, however, the analyses of the monthly samples shows significant variability (variation of greater than 20%) chemical composition, the frequency of analyses may be increased to that specified in item (i) above.

      (iii) Analysis of commingled injection fluids prior to injection shall be performed at random, **but not less than once every three months,** for total dissolved solids, pH, specific conductivity, specific gravity, major cations and anions, oil and grease, and total organic carbon.

   (b) *Monitoring of fluid sources accepted for disposal.* The permittee shall **maintain a record of each source of fluid received for disposal.** This record shall include the name of the source, the well name and API number if applicable, the volume of each load (in barrels), and the owner of the facility supplying the wastewater.

(c) *Continuous monitoring of flow rate and cumulative volume.* If the continuous monitoring is carried out with digital equipment, the instrumentation shall be capable of recording at least one value for each of the parameters at least every thirty (30) seconds. Initially, recordings shall be made once every ten (10) minutes. If the monitoring is recorded with a continuous chart recorder, the chart shall have a scale that will **allow a change in rate of 5 barrels per day to be detected.** Monitoring must occur whether or not fluids are being injected. This information shall be analyzed in the first annual report under this Permit to determine if this frequency is representative of the injection activity. A minor modification to the Permit shall be made to increase the frequency of recording if the variability of the injection volume and rate (as warranted by the data results) affects the representative nature of the data. A minor modification to the Permit may be made to decrease the frequency of recording if the Director determines that the fluctuation of the parameters is such that less frequent data collection would not significantly affect the representative nature of the reported data.

(d) *Continuous monitoring of injection and annulus pressure.* **Continuous monitoring shall be at the wellhead.** If the continuous monitoring is carried out with a continuous chart recorder, the chart shall be of a scale that **allows changes in pressure of 5 psi to be detected.** If the continuous monitoring is carried out with digital equipment, the instrumentation shall be capable of recording at least one value for each of the parameters at least every thirty (30) seconds. Initially, recordings should be made once every ten (10) minutes. Monitoring must occur whether or not fluids are being injected. **Manual reading from a pressure gage on the injection tubing and the annulus shall be taken daily for comparison to the continuous monitoring and recording devices.**

The information on pressure shall be analyzed in the first annual report to determine if the continuous monitoring equipment is providing information representative of the injection activity. If digital recording equipment is utilized, the analysis shall include an analysis of the representative nature of the recording frequency. A minor modification to the Permit shall be made to increase the frequency of recording if the variability of the injection pressure and annulus (as warranted by the data results) affects the representative nature of the data. A minor modification to the Permit may be made to decrease the frequency of recording if the Director determines that the fluctuation of the parameters is such that less frequent data collection would not significantly affect the representative nature of the reported data.

2. Monitoring Information. Records of any monitoring activity required under this permit shall include:

(a) The dates, exact place, and the time interval of sampling, monitoring, or field measurements;

(b) The name of the individual(s) who performed the sampling or measurements;

(c) The exact sampling method(s) used to take samples;

(d) The date(s) laboratory analyses were performed;

(e) The name of the individual(s) who performed the analyses;

(f) The analytical techniques or methods used by laboratory personnel; and

(g) The results of such analyses.

3. Recordkeeping.

(a) The permittee shall retain records concerning:

(i) the nature, volume, source and composition of all injected fluids until three (3) years after the completion of plugging and abandonment which has been carried out in accordance with the Plugging and Abandonment Plan shown in **Appendix C**.

(ii) all monitoring information, including all calibration and maintenance records and all original chart recordings or digital files for continuous monitoring instrumentation and copies of all reports required by this permit for a period of at least five (5) years from the date of the sample, measurement or report throughout the operating life of the well.

(b) The permittee shall continue to retain such records after the retention period specified in paragraphs (a) (i) and (ii) above unless he delivers the records to the Director or obtains written approval to discard them.

(c) The permittee shall maintain copies (or originals) of all pertinent records [Part II, Section D. 1. (a), (b), (c), and (d)] available for inspection at the office of:

4. <u>Reporting of Results</u>. The permittee shall submit Quarterly Reports to the Director summarizing the results of the monitoring required by Part II, Section D. 1. (a), (b), and (c) of this permit.

   (a) **The report shall include the monthly average, maximum, and minimum measured values for injection pressure, flow rate and volume, and annulus pressure. A list of all individual sources of waste fluids brought to the facility (including facility well name and API number, if applicable) and the total volume from each source shall be provided.**

   The operator shall also provide summary graphs covering the reporting period of the injection pressure, the annulus pressure, and the injection rate. Copies of the analytical results for the samples of injected fluids, and records of any major changes in characteristics or sources of injected fluid shall be included in the Quarterly Report.

   (b) The Quarterly Reports shall include the results and associated documentation of any **mechanical integrity testing, pressure falloff testing, well workover, or well logging** completed during the period covered by the report.

   (c) The first Quarterly Report shall cover the period from the effective date of the permit through the end of that quarter. Subsequent Quarterly Reports for a year shall cover the periods of: January 1 through March 31; April 1 through June 30; July 1 through September 30; and, October 1 through December 31. Each Quarterly Report shall be submitted to the Denver Office by the 15th of the following month. **Appendix B** contains Form 7520-8 which may be copied and used to submit the quarterly summary of monitoring.

E. PLUGGING AND ABANDONMENT

1. <u>Notice of Plugging and Abandonment</u>. The permittee shall notify the Director forty-five (45) days before abandonment of the well.

2. <u>Plugging and Abandonment Plan</u>. The permittee shall plug and abandon the well as provided in the Plugging and Abandonment Plan, **Appendix C**. The Director reserves the right to change the manner in which the well will be plugged if the well is modified during its permitted life or if the well is not made consistent with EPA

requirements for construction and mechanical integrity. The Director may ask the permittee to update the estimated plugging cost periodically. Such estimates shall be based upon costs which a third party would incur to plug the well according to the plan.

3. Inactive Wells. After a two (2) year period of injection inactivity, the permittee shall plug and abandon the well in accordance with the Plugging and Abandonment Plan, unless the permittee:

   (a) has provided notice to the Director; and

   (b) has demonstrated that the well will be used in the future; and

   (c) has described actions or procedures, satisfactory to the Director, that will be taken to ensure that the well will not endanger underground sources of drinking water during the period of temporary abandonment.

4. Plugging and Abandonment Report. **Within sixty (60) days after plugging the well, the permittee shall submit a report on Form 7520-13 to the Director**. The report shall be certified as accurate by the person who performed the plugging operation and the report shall consist of either: (1) a statement that the well was plugged in accordance with the plan; or (2) where actual plugging differed from the plan, a statement that specifies the different procedures followed.

F. FINANCIAL RESPONSIBILITY

1. Demonstration of Financial Responsibility. The permittee is required to maintain continuous financial responsibility and resources to close, plug and abandon the injection well as provided in the plugging and abandonment plan.

   (a) The permittee has submitted a Surety Performance Bond for $30,000 for this well, and a Standby Trust Agreement. Each have been reviewed and approved by the EPA. The Director may on a periodic basis revise the demonstration of financial responsibility under 40 CFR 144.53 (a) (7).

   (b) The permittee may, upon written request to EPA, change the type of financial mechanism or instrument utilized. A change in demonstration of financial responsibility must be approved by the Director. A minor permit modification will be made to reflect any change in financial mechanisms, without further opportunity for public comment.

2. Insolvency of Financial Institution. In the event that an alternate demonstration of financial responsibility has been approved under (b) above, the permittee must submit an alternate demonstration of financial responsibility acceptable to the

Director within sixty (60) days after either of the following events occur:

(a) The institution issuing the trust or financial instrument files for bankruptcy; or

(b) The authority of the trustee institution to act as trustee, or the authority of the institution issuing the financial instrument, is suspended or revoked.

3. Cancellation of Demonstration by Financial Institution. The permittee must submit an alternative demonstration of financial responsibility acceptable to the Director, within sixty (60) days after the institution issuing the trust or financial instrument serves 120-day notice to the EPA of their intent to cancel the trust or financial instrument.

PART III. GENERAL PERMIT CONDITIONS

A. EFFECT OF PERMIT

The permittee is allowed to engage in underground injection in accordance with the conditions of this permit. The permittee, as authorized by this permit, shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of fluid containing any contaminant into underground sources of drinking water, if the presence of that contaminant may cause a violation of any primary drinking water regulation under 40 CFR, Part 142 or otherwise adversely affect the health of persons. Any underground injection activity not authorized in this permit or otherwise authorized by permit or rule is prohibited. Issuance of this permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local law or regulations. Compliance with the terms of this permit does not constitute a defense to any enforcement action brought under the provisions of Section 1431 of the Safe Drinking Water Act (SDWA) or any other law governing protection of public health or the environment for any imminent and substantial endangerment to human health, or the environment, nor does it serve as a shield to the permittee's independent obligation to comply with all UIC regulations.

B. PERMIT ACTIONS

1. Modification, Reissuance, or Termination. The Director may, for cause or upon a request from the permittee, modify, revoke and reissue, or terminate this permit in accordance with 40 CFR Sections 124.5, 144.12, 144.39, and 144.40. Also, the permit is subject to minor modifications for cause as specified in 40 CFR Section 144.41. The filing of a request for a permit modification, revocation and reissuance, or termination or the notification of planned changes or anticipated noncompliance on the part of the permittee does not stay the applicability or enforceability of any

permit condition.

2. Transfers. This permit is not transferrable to any person except after notice is provided to the Director and the requirements of 40 CFR 144.38 are complied with. The Director may require modification, or revocation and reissuance, of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA.

3. Operator Change of Address. Upon the operator's change of address, notice must be given to the appropriate EPA office at least fifteen (15) days prior to the effective date.

C. SEVERABILITY

The provisions of this permit are severable, and if any provision of this permit or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR Part 2 and 40 CFR 144.5, any information submitted to EPA pursuant to this permit may be claimed as confidential by the submitter. Any such claim must be asserted at the time of submission by stamping the words "confidential business information" on each page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2 (Public Information). Claims of confidentiality for the following information will be denied:

- The name and address of the permittee; and
- Information which deals with the existence, absence or level of contaminants in drinking water.

E. GENERAL DUTIES AND REQUIREMENTS

1. Duty to Comply. The permittee shall comply with all conditions of this permit, except to the extent and for the duration that such noncompliance is authorized by an emergency permit. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, permit termination, revocation and reissuance, or modification. Such noncompliance may also be grounds for enforcement action under the Resource Conservation and Recovery Act (RCRA).

2. Penalties for Violations of Permit Conditions. Any person who violates a permit requirement is subject to civil penalties, fines, and other enforcement action under the SDWA and may be subject to such actions pursuant to the RCRA. Any person who willfully violates permit conditions may be subject to criminal prosecution.

3. Need to Halt or Reduce Activity not a Defense. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

4. Duty to Mitigate. The permittee shall take all reasonable steps to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.

5. Proper Operation and Maintenance. The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.

6. Surface Leak Prevention. The permittee shall operate and maintain the surface facility, including tanks, pumps, piping, and truck unloading area in a manner that prevents fluids delivered for disposal from Contaminating ground water. Therefore, the permittee shall:: (a) report to EPA and correct any problems that cause ground-water contamination; and (b) contract with an outside firm for an environmental audit of the facility once per year. The audit contract shall require the firm to report the results to EPA. The audit shall assess the adequacy of facility operations and maintenance in preventing ground-water contamination.

7. Duty to Provide Information. The permittee shall furnish the Director, within a time specified, any information which the Director may request in order to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with the permit. The permittee shall also furnish to the Director, upon request, copies of records required to be kept by this permit.

8. Inspection and Entry. The permittee shall allow the Director, or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

(a) Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this permit;

(b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

(c) Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and

(d) Sample or monitor, at reasonable times, for the purpose of assuring permit compliance, or as otherwise authorized by the SDWA, any substances or parameters at any location.

9. Records of Permit Application. The permittee shall maintain records of all data required to complete the permit application and any supplemental information submitted for a period of five (5) years from the effective date of this permit. This period may be extended by the Director at any time.

10. Signatory Requirements. All reports or other information requested by the Director shall be signed and certified according to 40 CFR 144.32.

11. Reporting of Noncompliance.

(a) Anticipated Noncompliance. The permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

(b) Compliance Schedules. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit, shall be submitted no later than thirty (30) days following each schedule date.

(c) Twenty Four Hour Noncompliance Reporting. **The operator shall report to the Director any noncompliance which may endanger health or the environment**. Information shall be provided, either orally or by leaving a message, within twenty-four (24) hours from the time the operator becomes aware of the circumstances by telephoning **1.800.227.8917 and asking for the EPA Region VIII UIC Program Compliance and Enforcement Director**, or by contacting the EPA Region VIII Emergency Operations Center at 303.293.1788 if calling from outside EPA Region VIII. The following information shall be included in the verbal report:

(i) Any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW.

(ii) Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between underground sources of drinking water.

(d) Oil Spill and Chemical Release Reporting. The operator shall comply with all other reporting requirements related to oil spills and chemical releases or other potential impacts to human health or the environment by contacting the National Response Center (NRC) at 1.800.424.8802 or 202.267.2675, or through the NRC website at http://www.nrc.uscg.mil/index.htm.

(e) Written Followup. A written submission shall also be provided within five (5) days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

(f) Other Noncompliance. The permittee shall report all other instances of noncompliance not otherwise reported at the time monitoring reports are submitted. The reports shall contain the information listed in Part III, Section E. 10. (c) (ii) of this permit.

(g) Other Information. Where the permittee becomes aware that any relevant facts were not submitted in the permit application, or incorrect information was submitted in a permit application or in any report to the Director, the permittee shall submit such correct facts or information within two (2) weeks of the time such information becomes known.

APPENDIX A

(CONSTRUCTION DETAILS)

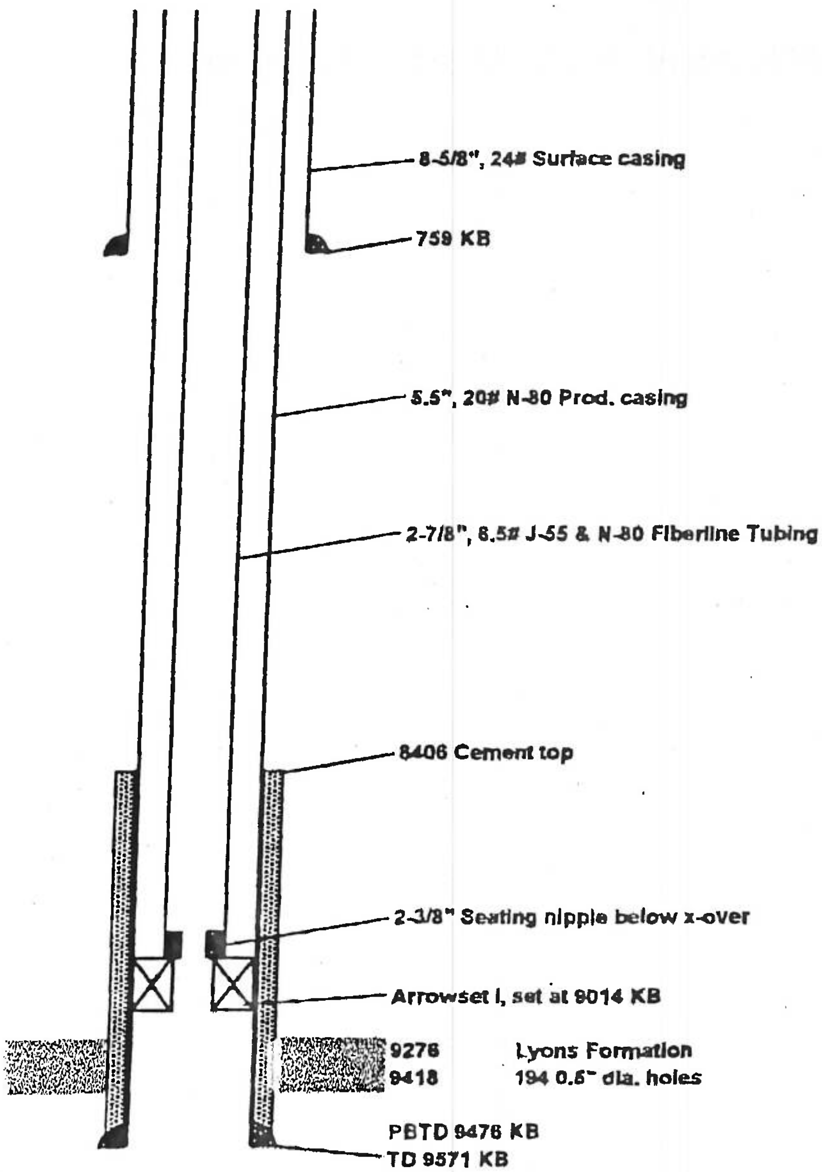
KPK
K.P. Kauffman Co., Inc.
Daily Workover or Completion Report

SUPERVISOR: Rick Ohlemeier

Well: Suckla Farms Injection Well #1	Road Dir: 19 at 10.5, 3/10E, N into		DATE: 1/31/01
L Desc: sene .0 1n 67w	County: Weld, CO	Line Locate: n/a	
Formation: Lyons	Perfs: 9276-9418, 194 holes		
Casing: 5.5" 20# N-80	TD: 9571	PBTD: 9476	KB Meas: 10

Tubing Detail, 1/31/01:

Footage	No. Jts.	
5496.54	173	Tbg 2-7/8" OD, EUE, 8rd, 6.5#, J-55, Fiberline
3499.35	110	Tbg 2-7/8" OD, EUE, 8rd, 6.5#, N-80, Fiberline
1.7	1	2-3/8"x2-7/8" x-over
1.1	1	Seating nipple, 2-3/8"
7.8	1	2-3/8"x5.5" Arrowset I (Rocky Mtn Oil Tools), set in compression
9006.49		TOTAL Set at 9014' KB



APPENDIX B

(REPORTING FORMS)

1. EPA Form 7520- 7: APPLICATION TO TRANSFER PERMIT
2. EPA Form 7520- 8: INJECTION WELL MONITORING REPORT
3. EPA Form 7520-10: COMPLETION REPORT FOR BRINE DISPOSAL WELL
4. EPA Form 7520-12: WELL REWORK RECORD
5. EPA Form 7520-13: PLUGGING RECORD
6. EPA Form R8: MECHANICAL INTEGRITY PRESSURE TEST

APPENDIX C

(PLUGGING & ABANDONMENT PLAN)

Plugging and Abandonment Plan

1. Immediately prior to plugging and abandoning the Suckla Farms #1 disposal well, the retrievable tension-type packer will be released and the tubing and packer will be removed from the wellbore.

2. Run back into the wellbore with a tubing stri g to the bottom of the 5-1/2 inch casing and condition the wellbore. Place a 2 0 foot cement plug from about 9,225 feet to 9, 476 feet, using either Class B type II neat cement or an equivalent Class G cement. Wait sufficient time for plug to set and tag plug with tubing string.

3. Cut the 5-12 inch long string casing at approximately 7,200 feet and pull the casing. Run into well with a tubing string and **condition the well with 9.6 ppg bentonite or plugging gel**. Set a 200 foot plug, using Class "G", or equivalent type cement, from 7,100 feet to 7,300 feet (a minimum of 75 feet below the top of the casing stub. If the casing is not pulled, the 5-1/2 inch casing must be perforated at 7,200 feet and cement squeezed into the annular space.

4. Within the 8-5/8 inch surface casing and the 7-7/8 inch wellbore, set a 100 foot plug, using Class "G" or equivalent cement, from 709 feet (50 feet above the surface casing shoe) to 809 feet. If the casing is not pulled, the 5-1/2 inch casing must be perforated at just below the casing shoe and cement squeezed into the annular space.

5. Within the 8-5/8 inch surface casing, set a cement plug, using sufficient Class "G" cement to fill the surface casing from the surface to a minimum depth of 50 feet. If the casing is not pulled, the 5-1/2 inch casing must also be filled with Class "G" cement to a minimum depth of 50 feet.

6. After the wellbore is plugged the Permit requires cutting off the 8-5/8 inch casing 1 to 3 feet below ground surface. A steel cap dry hole marker is required to be welded on the 8-5/8 inch casing. The surface must then be restored to landowner and/or County requirements.

Approv... No. 2000-0042. Approval expires 5-30-...

UNITED STATES ENVIRONMENTAL PROT...N AGENCY
WASHINGTON, DC 20460

EPA

APPLICATION TO TRANSFER PERMIT

NAME AND ADDRESS OF EXISTING PERMITTEE	NAME AND ADDRESS OF SURFACE OWNER

LOCATE WELL AND OUTLINE UNIT ON SECTION PLAT — 640 ACRES

N

W E

S

STATE	COUNTY	PERMIT NUMBER

SURFACE LOCATION DESCRIPTION

¼ OF ¼ OF ¼ SECTION TOWNSHIP RANGE

LOCATE WELL IN TWO DIRECTIONS FROM NEAREST LINES OF QUARTER SECTION AND DRILLING UNIT

Surface Location ____ ft. from (N/S) ____ Line of quarter section

and ____ ft. from (E/W) ____ Line of quarter section

WELL ACTIVITY	WELL STATUS	TYPE OF PERMIT
☐ Class I ☐ Class II ☐ Brine Disposal ☐ Enhanced Recovery ☐ Hydrocarbon Storage ☐ Class III ☐ Other	☐ Operating ☐ Modification/Conversion ☐ Proposed	☐ Individual ☐ Area Number of Wells ____

Lease Name Well Number

NAME(S) AND ADDRESS(ES) OF NEW OWNER(S)	NAME AND ADDRESS OF NEW OPERATOR

Attach to this application a written agreement between the existing and new permittee containing a specific date for transfer of permit responsibility, coverage, and liability between them.

The new permittee must show evidence of financial responsibility by the submission of surety bond, or other adequate assurance, such as financial statements or other materials acceptable to the director.

CERTIFICATION

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

NAME AND OFFICIAL TITLE (*Please type or print*)	SIGNATURE	DATE SIGNED

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, DC 20460

Form Approved
OMB No. 2040-0042
Approval expires 5-30-86

EPA

COMPLETION REPORT FOR BRINE DISPOSAL, HYDROCARBON STORAGE, OR ENHANCED RECOVERY WELL

NAME AND ADDRESS OF EXISTING PERMITTEE

NAME AND ADDRESS OF SURFACE OWNER

STATE | COUNTY | PERMIT NUMBER

LOCATE WELL AND OUTLINE UNIT ON SECTION PLAT — 640 ACRES

N
W E
S

SURFACE LOCATION DESCRIPTION
¼ OF ¼ OF ¼ SECTION TOWNSHIP RANGE

LOCATE WELL IN TWO DIRECTIONS FROM NEAREST LINES OF QUARTER SECTION AND DRILLING UNIT

Surface
Location ____ ft. from (N/S) ____ Line of quarter section
and ____ ft. from (E/W) ____ Line of quarter section

WELL ACTIVITY
☐ Brine Disposal
☐ Enhanced Recovery
☐ Hydrocarbon Storage

TYPE OF PERMIT
☐ Individual
☐ Area
Number of Wells ____

Estimated Fracture Pressure of Injection Zone

Anticipated Daily Injection Volume (Bbls)
Average | Maximum

Injection Interval
Feet | to Feet

Anticipated Daily Injection Pressure (PSI)
Average | Maximum

Depth to Bottom of Lowermost Freshwater Formation (Feet)

Type of Injection Fluid *(Check the appropriate block(s))*
☐ Salt Water ☐ Brackish Water ☐ Fresh Water
☐ Liquid Hydrocarbon ☐ Other

Lease Name | Well Number

Name of Injection Zone

Date Drilling Began | Date Well Completed

Permeability of Injection Zone

Date Drilling Completed

Porosity of Injection Zone

CASING AND TUBING			CEMENT		HOLE	
OD Size	Wt/Ft — Grade — New or Used	Depth	Sacks	Class	Depth	Bit Diameter

INJECTION ZONE STIMULATION		WIRE LINE LOGS, LIST EACH TYPE	
Interval Treated	Materials and Amount Used	Log Types	Logged Intervals

Complete Attachments A — E listed on the reverse.

CERTIFICATION

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32).

NAME AND OFFICIAL TITLE *(Please type or print)* | SIGNATURE | DATE SIGNED

Form Approved. OMB No. 2000-0042. Approval expires 5-30-86

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, DC 20460

EPA

ANNUAL DISPOSAL/INJECTION WELL MONITORING REPORT

NAME AND ADDRESS OF EXISTING PERMITTEE	NAME AND ADDRESS OF SURFACE OWNER

LOCATE WELL AND OUTLINE UNIT ON SECTION PLAT — 640 ACRES

N

W E

S

STATE	COUNTY	PERMIT NUMBER

SURFACE LOCATION DESCRIPTION

¼ OF ____ ¼ OF ____ ¼ SECTION ____ TOWNSHIP ____ RANGE ____

LOCATE WELL IN TWO DIRECTIONS FROM NEAREST LINES OF QUARTER SECTION AND DRILLING UNIT

Surface Location ____ ft. from (N/S) ____ Line of quarter section

and ____ ft. from (E/W) ____ Line of quarter section

WELL ACTIVITY

- ☐ Brine Disposal
- ☐ Enhanced Recovery
- ☐ Hydrocarbon Storage

TYPE OF PERMIT

- ☐ Individual
- ☐ Area

Number of Wells ____

Lease Name

Well Number

		INJECTION PRESSURE		TOTAL VOLUME INJECTED		TUBING — CASING ANNULUS PRESSURE (OPTIONAL MONITORING)	
MONTH	YEAR	AVERAGE PSIG	MAXIMUM PSIG	BBL	MCF	MINIMUM PSIG	MAXIMUM PSIG

CERTIFICATION

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32).

NAME AND OFFICIAL TITLE (Please type or print)	SIGNATURE	DATE SIGNED

Form ... c. 2000-0042. Approval expires 5-30-86

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, DC 20460

EPA

WELL REWORK RECORD

NAME AND ADDRESS OF PERMITTEE	NAME AND ADDRESS OF CONTRACTOR

LOCATE WELL AND OUTLINE UNIT ON SECTION PLAT — 640 ACRES

N / W / E / S

STATE	COUNTY	PERMIT NUMBER

SURFACE LOCATION DESCRIPTION

¼ OF ___ ¼ OF ___ ¼ SECTION ___ TOWNSHIP ___ RANGE ___

LOCATE WELL IN TWO DIRECTIONS FROM NEAREST LINES OF QUARTER SECTION AND DRILLING UNIT

Surface
Location ____ ft. from (N/S) ____ Line of quarter section
and ____ ft. from (E/W) ____ Line of quarter section

WELL ACTIVITY		TYPE OF PERMIT
☐ Brine Disposal ☐ Enhanced Recovery ☐ Hydrocarbon Storage	Total Depth Before Rework	☐ Individual ☐ Area Number of Wells ____
	Total Depth After Rework	
Lease Name	Date Rework Commenced	Well Number
	Date Rework Completed	

WELL CASING RECORD — BEFORE REWORK

Casing		Cement		Perforations		Acid or Fracture
Size	Depth	Sacks	Type	From	To	Treatment Record

WELL CASING RECORD — AFTER REWORK *(Indicate Additions and Changes Only)*

Casing		Cement		Perforations		Acid or Fracture
Size	Depth	Sacks	Type	From	To	Treatment Record

DESCRIBE REWORK OPERATIONS IN DETAIL USE ADDITIONAL SHEETS IF NECESSARY	WIRE LINE LOGS, LIST EACH TYPE	
	Log Types	Logged Intervals

CERTIFICATION

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32).

NAME AND OFFICIAL TITLE *(Please type or print)*	SIGNATURE	DATE SIGNED

D STATES ENVIRONMENTAL PROTECT... AGENCY
WASHINGTON, DC 20460

EPA

PLUGGING RECORD

AND ADDRESS OF PERMITTEE	NAME AND ADDRESS OF CEMENTING COMPANY

STATE	COUNTY	PERMIT NUMBER

...ATE WELL AND OUTLINE UNIT ON ...TION PLAT — 640 ACRES

N

E

S

SURFACE LOCATION DESCRIPTION

¼ OF ¼ OF ¼ SECTION TOWNSHIP RANGE

LOCATE WELL IN TWO DIRECTIONS FROM NEAREST LINES OF QUARTER SECTION AND DRILLING UNIT

Surface Location ____ ft. from (N/S) ____ Line of quarter section

and ____ ft. from (E/W) ____ Line of quarter section

TYPE OF AUTHORIZATION

☐ Individual Permit
☐ Area Permit
☐ Rule

Number of Wells ____

Lease Name

Describe in detail the manner in which the fluid was placed and the method used in introducing it into the hole

CASING AND TUBING RECORD AFTER PLUGGING

	WT(LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE

WELL ACTIVITY

☐ CLASS I
☐ CLASS II
☐ Brine Disposal
☐ Enhanced Recovery
☐ Hydrocarbon Storage
☐ CLASS III

METHOD OF EMPLACEMENT OF CEMENT PLUGS

☐ The Balance Method
☐ The Dump Bailer Method
☐ The Two-Plug Method
☐ Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
...e or Pipe in which Plug Will Be Placed (inches)							
Bottom of Tubing or Drill Pipe (ft.)							
Cement To Be Used (each plug)							
...ume To Be Pumped (cu. ft.)							
...Top of Plug (ft.)							
...Top of Plug (if tagged ft.)							
...(Lb./Gal.)							
...ent or Other Material (Class III)							

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS

From	To	From	To

...re of Cementer or Authorized Representative	Signature of EPA Representative

CERTIFICATION

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations. (REF. 40 CFR 122.22)

...D OFFICIAL TITLE (Please type or print)	SIGNATURE	DATE SIGNED

Mechanical Integrity Test

Casing or Annulus Pressure Mechanical Integrity Test

U.S. Environmental Protection Agency
Underground Injection Control Program
999 18th Street, Suite 500 Denver, CO 80202-2466

Date: ____ / ____ / ____

EPA Witness: ______________________________

Test conducted by: ______________________________

Others present: ______________________________

Well Name: ____________________ Type: ER SWD Status: AC TA UC

Field: ____________________ County: ____________________ State: ____

Location: __________ Sec: ____ T ____ N / S R ____ E / W

Operator: ______________________________

Last MIT: ____ / ____ / ____ Maximum Allowable Pressure: ____________ PSIG

Is this a regularly scheduled test? [ ] Yes [ ] No

Initial test for permit? [ ] Yes [ ] No

Test after well rework? [ ] Yes [ ] No

Well injecting during test? [ ] Yes [ ] No If Yes, rate: ____________ bpd

Pre-test casing/tubing annulus pressure: ____________ psig

MIT DATA TABLE	Test #1	Test #2	Test #3
TUBING	*PRESSURE*		
Initial Pressure	psig	psig	psig
End of test pressure	psig	psig	psig
CASING / TUBING	*ANNULUS*	*PRESSURE*	
0 minutes	psig	psig	psig
5 minutes	psig	psig	psig
10 minutes	psig	psig	psig
15 minutes	psig	psig	psig
20 minutes	psig	psig	psig
25 minutes	psig	psig	psig
30 minutes	psig	psig	psig
______ minutes	psig	psig	psig
______ minutes	psig	psig	psig
RESULT	[ ] Pass [ ]Fail	[ ] Pass [ ]Fail	[ ] Pass [ ]Fail

Does the annulus pressure build back up after the test ? [ ] Yes [ ] No

MECHANICAL INTEGRITY PRESSURE TEST

Additional comments for mechanical integrity pressure test, such as volume of fluid added to annulus and bled back at end of test, reason for failing test (casing head leak, tubing leak, other), etc.: ____________

APPENDIX D

(CEMENT BOND LOGGING TECHNIQUES AND INTERPRETATION)

APPENDIX D

(CEMENT BOND LOGGING TECHNIQUES AND INTERPRETATION)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

APR 19 1994

SUBJECT: GROUND WATER SECTION GUIDANCE NO. 34
Cement bond logging techniques and interpretation

FROM: Tom Pike, Chief
UIC Direct Implementation Section

TO: All Section Staff
Montana Operations Office

These procedures are to be followed when running and interpreting cement bond logs for injection and production (area of review) wells.

PART I - PREPARE THE WELL

Allow cement to cure for a sufficient time to develop full compressive strength. A safe bet is to let the cement cure for 72 hours. If you run the bond log before the cement achieves its maximum compressive strength, the log may show poor bonding. Check cement handbooks for curing times.

Circulate the hole with a fluid (either water or mud) of uniform consistency. Travel times are influenced by the type of fluid in the hole. If the fluid changes between two points, the travel times may "drift," causing difficulty in interpretation and quality control.

Be prepared to run the cement bond log under pressure to reduce the effects of micro-annulus. Micro-annulus may be caused by several reasons, but the existence of a micro-annulus does not necessarily destroy the cement's ability to form a hydraulic seal. If the log shows poor bonding, rerun the log with the slightly more pressure on the casing as was present when the cement cured. This will cause the casing to expand against the cement and close the micro-annulus.

PART II - PARAMETERS TO LOG

Amplitude (mV) - This curve shows how much acoustic signal reaches a receiver and is an important indicator of cement bond. Record the amplitude on the 3 foot spaced receiver.

Travel time (μs) - This curve shows the amount of time it takes an acoustic signal to travel between the source and a receiver. For free pipe of a given size and weight, the travel time between points is very predictable, although variable among different company's tools. Service companies should be able to provide accurate estimates of travel times for free pipe of a given size and weight. Travel time is required as a quality control measurement. Record the travel time on the 3 foot spaced receiver.

variable among different company's tools. Service companies should be able to provide accurate estimates of travel times for free pipe of a given size and weight. Travel time is required as a quality control measurement. Record the travel time on the 3 foot spaced receiver.

Variable density (VDL) - Pipe signals, formation signals, and fluid signals are usually easy to recognize on the VDL. If these signals can be identified, a practical determination for the presence or absence of cement can be made. VDL is logged on the 5 foot spaced receiver.

Casing collar locator (CCL) - Used to correlate the bond log with cased hole logs and to match casing collars with the collars that show up on the VDL portion of the display.

Gamma ray - Used to correlate the bond log with other logs.

PART III - LOGGING TECHNIQUE

Calibrate the tool in free pipe at the shop, prior to, and following the log run. Include calibration data with log.

Run receivers spaced 3 feet and 5 feet from transmitter.

Run at least 3 bow-type or rigid aluminum centralizers in vertical holes, 6 centralizers in directional holes. A CCL is not an adequate centralizer.

Complete log header with casing/cement data, tool/panel data, gate settings and tool sketch showing centralizers.

Set the amplitude gate so that skipping does not occur at amplitudes greater than 5 mV.

Record amplitude with fixed gate and note position on log.

Record amplified amplitude on a 5X scale for low amplitudes.

Record amplitude and travel time on the 3 foot receiver.

Record travel time on a 100 µs scale (150 - 250, 200 - 300).

Logging speed should be approximately 30 ft/min.

Log repeat sections.

PART IV - QUALITY CONTROL

Compare the tool calibration data to see if the tool "drifts" during logging. Differences in the calibration data may require you to re-log the well to obtain reliable data.

Compare repeat sections to see if logging results are repeatable.

Check the logged free pipe travel times with the service company charts for the specific tool and casing size used. Since the travel times depend on such factors as casing weight, type of fluid in the hole, etc., these charts should be used only as guidelines. When you are confident of the free-pipe travel times as seen on the log, use them. When interpreting the log, a decrease in travel time (faster times) with simultaneous reduction of amplitude may show a de-centered tool. A 4 to 5 micro-second (µs) decrease in travel time corresponds to about a 35% loss of amplitude. A decrease in travel time more than 4 to 5 µs is unacceptable.

PART V - LOG INTERPRETATION

Do not rely on the service company charts for amplitudes corresponding to a good bond. These amplitudes depend on many factors: type of cement used, fluid in the hole, etc.

To estimate bond index, choose intervals on the log that correspond to 0% bond and 100% bond. Read the amplitude corresponding to 100% bond from the best-bonded interval on the log (NOTE: the accuracy of this amplitude reading is very critical to the bond index calculations). Next, find the amplitude corresponding to 0% bond. Some bond logs may not include a section with free pipe. In this instance, choose the appropriate free-pipe travel time from the service company charts for your specific tool, or from the generalized chart (TABLE 2) at the end of this guidance. To calculate a bond index of 80%, use the following equation:

$$A_{80} = 10^{[(0.2)\log(A_0) + (0.8)\log(A_{100})]}$$

where:

A_{80} = Amplitude at 80% bond (mV)
A_0 = Amplitude at 0% bond (mV)

A_{100} = Amplitude at 100% bond (mV)

EXAMPLE:

As an example, consider a bond log showing the following conditions:

- Free pipe (0% bond) amplitude at 81 mV.

- 100 % bond amplitude at 1 mV.

Substituting the above values into the equation results in:

$$A_{80} = 10^{[(0.2)\log(81) + (0.8)\log(1)]}$$

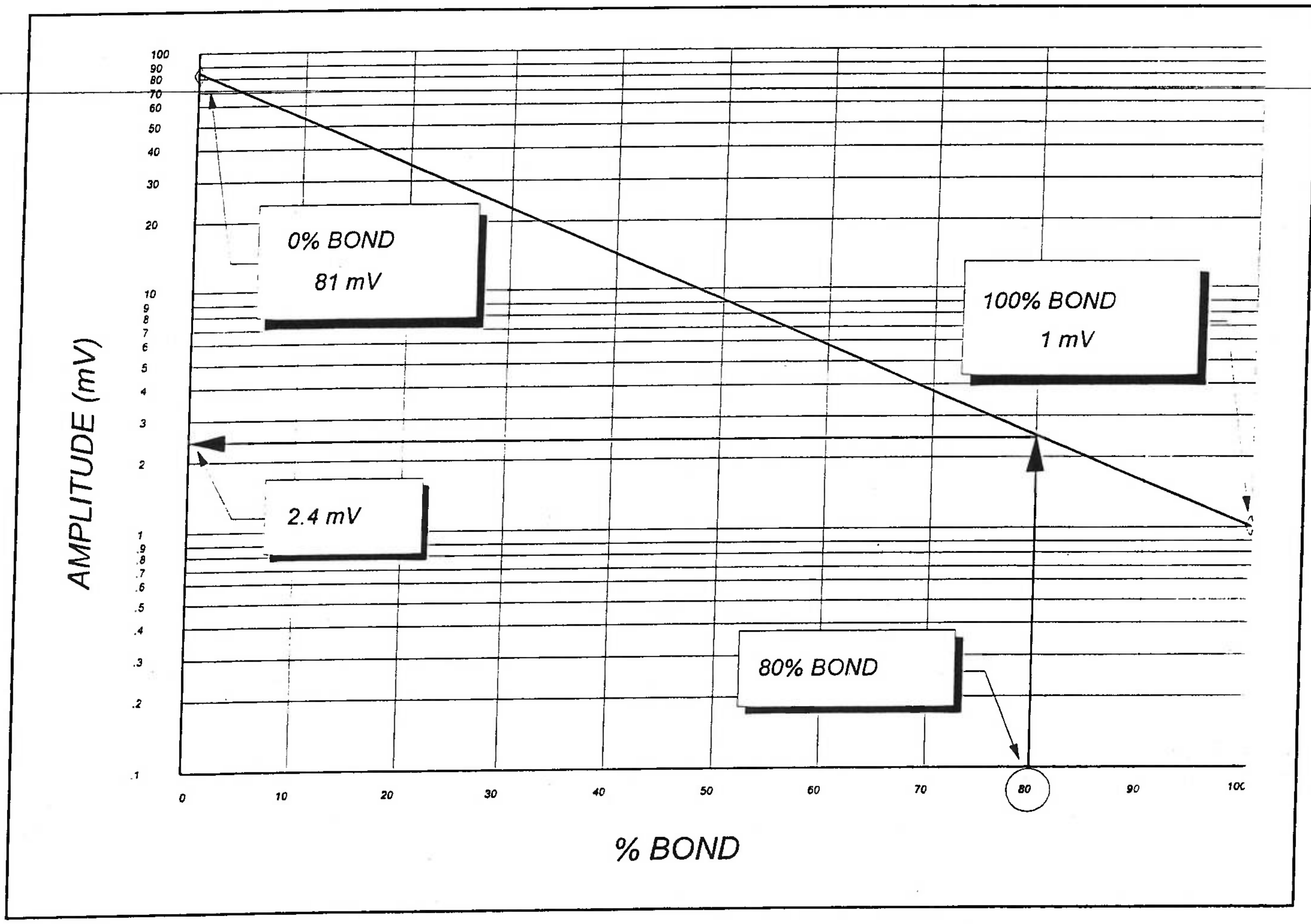
$$A_{80} = 2.41mV$$

Another way to calculate the amplitude at 80% bond is by plotting these same log readings on a semi-log chart.

Plot the values for 0% Bond and 100% Bond vs. their respective Amplitudes on a semi-log chart - amplitudes on the log scale (y-axis), and bond indices on the linear scale (x-axis). Then, connect the points with a straight line.

To estimate the amplitude corresponding to an 80% Bond Index, enter the graph on the x-axis at 80% bond. Draw a straight line upward until you reach the diagonal line connecting the 0% and 100% points. Continue by drawing a horizontal line to the y-axis. This point on the y-axis is the amplitude corresponding to an 80% Bond Index.

Using the values from the example above, your chart will look like that shown below:



In this example, 80% bond shows an amplitude of 2.4 mV.

A convenient way to evaluate the log is to draw a line on the bond log's **amplified** amplitude (5X) track corresponding to the calculated 80% bond amplitude. Whenever the logged **amplified** amplitude (5X) curve drops below (to the left of) the drawn line, this indicates a bond of 80% or more.

PART IV - CONCLUSIONS - REMINDERS

Different pipe weights and cement types will affect the log readings, so be mindful of these factors in wells with varying pipe weights and staged cement or squeeze jobs.

Collars generally do not show up on the VDL track in well-bonded sections of casing.

Longer (slower) travel time due to cycle skipping or cycle stretch usually suggests good bonding.

Shorter (faster) travel times indicate a de-centered tool or a fast formation and will provide erroneous amplitude readings that make evaluation impossible through that section of the log. Fast formations do not assure that the cement contacts the formation all around the borehole.

Although the bond index is important, you should not base your assessment of the cement quality on that one factor alone. You should use the VDL to support any indication of bonding. Also, you must know how each portion of the CBL (VDL, travel time, amplitude, etc.) influences another.

Most 3'-5' CBL's cannot identify a 1/2" channel in cement. Therefore, you also need to consider the thickness of a cemented section needed to provide zone isolation. For adequate isolation in injection wells, the log should indicate a continuous 80% or greater bond through the following intervals as seen in TABLE 1, below:

TABLE 1 - INTERVALS FOR ADEQUATE BOND

PIPE DIAMETER (in)	CONTINUOUS INTERVAL WITH BOND ≥ 80% (ft)
4-1/2	15
5	15
5-1/2	18
7	33
7-5/8	36
9-5/8	45
10-3/4	54

Adequately bonded cement by itself will not prevent fluid movement. If the bond log shows adequate bond through an interval where the geology allows fluid to move (permeable and/or fractured zones), fluids may move around perfectly bonded cement by travelling through the formation. <u>Always</u> cross-check your bond log with open hole logs to see that you have adequate bonding through the proper interval(s).

TABLE 2 - TRAVEL TIMES AND AMPLITUDES FOR FREE PIPE
(3 FT RECEIVER)

CASING SIZE (in)	CASING WEIGHT (lb/ft)	TRAVEL TIME (µs)		AMPLITUDE (mV)
		1-11/16" TOOL	3-5/8" TOOL	
4-1/2	9.5	252	233	81
	11.6	250	232	81
	13.5	249	230	81
5	15.0	257	238	76
	18.0	255	236	76
	20.3	253	235	76
5-1/2	15.5	266	248	72
	17.0	265	247	72
	20.0	264	245	72
	23.0	262	243	72
7	23.0	291	271	62
	26.0	289	270	62
	29.0	288	268	62
	32.0	286	267	62
	35.0	284	265	62
	38.0	283	264	62
7-5/8	26.4	301	281	59
	29.7	299	280	59
	33.7	297	278	59
	39.0	295	276	59
9-5/8	40.0	333	313	51
	43.5	332	311	51
	47.0	330	310	51
	53.5	328	309	51
10-3/4	40.5	354	333	48
	45.5	352	332	48
	51.0	350	330	48
	55.5	349	328	48

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
999 18TH STREET - SUITE 300
DENVER, CO 80202-2466
http://www.epa.gov/region08

January 17, 2001

CEMENT EVALUATION NOTES

Compiled for the MIT Workgroup
by
Jerry T. Thornhill
USEPA, Robert S. Kerr Research Lab.
Edited
by
Paul S. Osborne
USEPA, Region VIII

Background-Acoustic Cement Bond Logging

The Reasons for cementing wells are: 1) to support the casing; and 2) to isolate zones (hydraulic seal), such as producing horizons, injection reservoirs, and underground sources of drinking water (USDW). When a well is completed, a cementing record will be submitted as part of the well completion record. This information will not address the question regarding the adequacy of the cement to isolate the various zones. One of the methods utilized to assess the adequacy of the cementing of a well to isolate the various zones is by using an acoustic cement bond log (CBL). Although an acoustic cement bond logs does not directly measure hydraulic seal, the measured bonding qualities do provide inferences of sealing adequacy (zone isolation). The bonding of cement to the casing can be measured quantitatively using a CBL. The bonding of cement to the formation, however cannot be measured quantitatively using a CBL, but it does provide a qualitative estimate of the bonding to the formation. Determination of cement integrity is accomplished by an analysis of the full acoustic waveform, the amplitude or attenuation rates of the casing arrivals, and a single receiver travel-time measurement.

The Acoustic CBL tool used to make the cement bond log puts energy into the well and measures the energy returned. The operating frequency for all conventional instruments is 20 kHz. The time it takes for energy to return and the amplitude of the returned energy are determined by the cement bonding. Elastic compressional waves are propagated down the sleeve of the instrument, vertically through the borehole fluid, and horizontally across the borehole fluid. Of primary interest to the CBL log is the wavefront moving directly toward the casing. As the wave front impinges upon the casing, some energy is reflected, while the balance is transferred into the steel, the cement sheath and the formation. Acoustic energy propagates through fluid at about 180-220 microseconds per foot, and about 57 microseconds per foot through steel. At each of these interfaces, some energy will be reflected, and some will be transferred into the adjoining medium. The reflected waves coming back from the various interfaces are recorded preferably by two detectors located 3 and 5 feet from the acoustic transmitter. The log results are recorded on five curves: 1) a gamma ray curve for lithologic correlation; 2) a casing collar locator for depth correlation; 3) an amplitude curve derived from the 3 foot receiver as a measure of casing bonding; 4) a travel time curve which is an indicator of the centralization of the tool; and 5) a variable density log (VDL) and or signature wave forms from the 5 foot receiver as a measure of the formation bonding.

CBL Requirements

The requirements for obtaining a meaningful cement bond log are:

1. The Tool must be centered in the casing.

2. The transmitter and receiver(s) must be a known distance apart.
   The most common transmitter/receiver spacing is 3 feet. This spacing is ideal for measuring fastest sound travel which is through the casing and is used for amplitude and travel time measurements. The attenuation of this signal is a measure of the bonding of the cement to the casing. It is useless for looking at formation bonding.

   The 5 foot receiver is used to record variable density and/or signature waveforms. This spacing will not show the casing signal but will show the formation signal. The preferred tool has a transmitter with two receivers spaced 3 foot and 5 foot from the transmitter. This arrangement gives the casing signal (3 foot receiver) recorded as the amplitude curve and formation signal (5 foot receiver) recorded as the VDL trace.

   A 4 foot spacing (single receiver) has been tried as a compromise. It still does not show formation signals.

3. The "gate" must be set properly. Figure A-2 indicates the wave form being investigated. T sub o represents when the tool is turned on. Dead time is the time it takes to receive the first signal (E1 through El). As shown in Figure A-4, E1 to E3 are measured to determine the casing bonding (3 foot receiver signal). The signals from this receiver give an evaluation of the amplitude changes the sonic energy will experience on its path along the casing.

   Tool systems are gated to measure a particular part of the wave train. Acoustic logging instrumentation uses both fixed and floating gates. A fixed gate system is one in which the transmitter is fired at fixed intervals, followed by a fixed time for the gate to open and remain open, and fixed time interval for the gate to close. Fixed gates are currently being used for primary bond amplitude measurements; however, prior to development of full waveform recordings, older generation

CBl's used a floating gate amplitude measurement with a floating gate travel-time curve to evaluate cement conditions.

The principle of the floating gate is that it remains open across the entire acoustic spectrum until an amplitude pulse having sufficient amplitude to extend beyond the threshold bias setting is found. This response is then recorded as the time of the first acoustic arrival pulse.

The basic waveform consists of four different types of wave arrivals:

a. compressional wave in casing ,
b. compressional wave in the cement sheath,
c. compressional, shear, pseudo-Rayleigh, and Stonefey waves in the formation, and
d. mud or fluid waves.

4. The fluid wave travels through the fluid straight to the receiver. After the fluid wave shows up, the V DL is useless. When the fluid wave enters the receiver, distortion occurs. Therefore, the useful part of the V DL is that prior to the fluid wave. When shear waves are detected on the Signature or Variable Density, they are representative of cement integrity in the overwhelming majority of cases.

5. A reliable cement bond log will have the following:
3 foot -5 foot RECEIVER SPACING
GAMMA-RA Y
CASING COLLAR LOCATOR
AMPLITUDE CURVE
TRAVEL TIME CURVE
VARIABLE DENSITY DISPLAY

Amplitude Curve Interpretation

A. A high amplitude indicates that the casing is relatively free to vibrate; hence, it is poorly bonded or supported.

B. A low amplitude indicates that the casing is more confined or bonded, causing absorption of the wave energy by surrounding media.

C. Amplitude measurements between maximum and minimum values are functions of the percentage of casing bond.

THIS SINGLE MEASUREMENT (AMPLITUDE), AND THE OVERSIMPLIFIED INTERPRETATION OF IT, IS FREQUENTLY THE SOURCE OF MUCH OF THE CONTROVERSY AND ERROR REGARDING CEMENT BOND LOG ANALYSIS.

To analyze a bond log, ignore the amplitude curve initially, go to the V DL and measure the casing signal for free pipe. If the casing signal is not present, the signal must have been attenuated. Then, go to the amplitude curve. Determine the time of the first arrivals and their character. VDL formation signals should generally correlate with the gamma log. The V DL is practically tamper-proof. The operator cannot change the property of the rock, thus the time required for the signal to be transmitted.

<u>Pitfalls in Bond Interpretation from Amplitude Response</u>

A. Amplitude detection method -fixed gate or floating gate..

B. Instrument centering..

C. Insufficient curing time for cement.

D. Cement sheath less than 314 inch with either well centered or poorly centered casing .

E. Micro annulus.

F. Gas bubbles in the borehole fluid.

G. Void spaces in the cement sheath.

H. Fast formation.

I. Cement bonded to the pipe. but not to the formation.

J. Changes in acoustic properties of the borehole fluid density and viscosity die to pressure. temperature, and content.

K. Minimum amplitude signal in well bonded casing varies with respect to casing size and casing weight.

L. Cements are mixed to particular specifications and may be designed with different compressive strengths.

M. Cement is sometimes gas cut.

CBL Log Quality Checks

Free Pipe

A. Travel time indicating correct expected value for casing size and weight?

B. ~~Travel time, magnetic collar locator, amplitude curve and variable~~ density/waveform all indicating casing collars on depth with each other?

C. Free pipe amplitude reading correct value for casing size and weight?

D. E1 arrival on variable density display indicating correct travel time to 5 foot receiver, (i.e. 114 microseconds later than 3 foot receiver travel time)?

E. Collars on amplitude curve are 3 foot in vertical height and 5 foot on VDL. This ensures amplitude and VDL/WF are measured on proper receiver .

Cemented Pipe

A. Travel time stretching or cycle skipping occurring in well bonded sections.

B. 100% and 70% bonded intervals consistent with minimum sonic amplitude picked from CBL interpretation chart?

C. Is travel time less than free pipe value indicating eccentering or fast formation ?

D. If eccentering is expected, check V DL for chevron pattern at collars and low CBL amplitudes.

E. If fast formation is suspected, i.e. open hole logs indicate delta T less than 57 microseconds per foot, check 1st formation arrival on VDL/WF. If less than expected free pipe value on 5 foot receiver, fast formation can be confirmed. Note: pre-log planning will alert operator to presence of fast formations.

F. Have log passes been run under sufficient pressure to eliminate Micro annulus effect?

G. Does main log pass agree with repeat section?

H. Is main log pass properly correlated to open hole log? Note: if perforations are picked from a pressure pass, make sure field personnel are aware of this and that proper correlation is taken into account prior to perforating.

Instrument Centering

A. If the logging instrument is properly centered in free or poorly bonded pipe, the travel time should be a reasonably precise value.

B. Travel time measurement is the time it takes the signal to leave the transmitter and return to the receiver. This is not formation bonding. There is no way to tell formation bonding quantitatively. Travel time can be very useful. It can be used to determine whether or not the tool is centralized. Travel time will occur early if an instrument is poorly centered.

C. Amplitude can also increase when casing is eccentered because a portion of the annular cement sheath is either absent or extremely thin. (less than 3/4 inch).

Cycle Skipping

Cycle skipping to later amplitude arrivals is caused by the attenuation of pipe arrivals.

Stretch

A. Travel-time stretch may occur when an attenuated first pipe arrival is detected in bonded intervals.

B. Stretch is often an indication of adequate zone isolation.

Casing Collars

A. Casing collars are identified as a decrease in the amplitude, a slight increase in TT, and/or clear chevron ("W") patterns on the VDL..

B. The distance between the "W" pattern corners on the V DL represents the transmitter-receiver spacing.

C. Casing collar anomalies are typically not apparent in well bonded casing.

D. Caliper information defining the size and perhaps the shape and rugosity of the borehole wall behind pipe is always an important criteria to log analysis of cement condition.

Calibration

Well Site Calibration Procedure (Wedge Wireline)

A. With tool in hole and in fluid, panel output is calibrated for a linear output relation of 100 mv. for 10 chart divisions-10 mv/div. This calibration is done in order to scale the amplitude values.

B. Secondary amplitude x 4 or x5 is calibrated.

C. Internal calibration cycle of 35 mv. amplitude and 50 microseconds wave length is activated; the Gate is set on the cycle, and amplitude deflection is adjusted according to previous 0-100 mv. settings.

D. Calibration cycle is deactivated. tool signal on 3 foot receiver is present; the gate is set on the first compressional cycle, and amplitude reading is verified. It should be noted that our system does not rely on free pipe sections in order to calibrate or adjust the amplitude curve.

Shop Calibration (Wedge Wireline)

A. The tool is centered inside a section of 5.5 inch, 15 lb/ft. casing ; completely covered with water; the tank is pressured to 5000 psi.; the signal on the 3 foot receiver is adjusted for a maximum output of 80 mv.

B. Signal output on the 5 foot receiver is adjusted in order to compensate for energy loss related to the 3 foot receiver, due to the extended travel time of 114 microseconds, which usually ranges in the order of 30% loss.

C. Panels are calibrated for response and linearity.

D. After the above procedure is completed, a full display of calibration is recorded for every tool.

Notes:

An internal electrical calibration for the peak amplitude measurement is utilized to calibrate the instrument. (Atlas Wireline)

The shop calibration fixture utilized is a 5.5 inch OD aluminum pressure tube. The tube is filled with water and pressured up to 500 psi or greater.

(Atlas Wireline).

Shop calibrations are required monthly or more frequently as needed.

A complete calibration sequence requires BEFORE and AFTER records, including Signature (or V DL) and travel time calibrations.

SECOND-GENERATION RADIAL CEMENT EVALUATION INSTRUMENT

The Segmented Bond Tool (SBT) is a promising second-generation radial cement bond instrument, which measures the quality of cement effectiveness both vertically and laterally around the
circumference of the casing. The SBT is designed to quantitatively measure six segments, 60 degrees each, around the pipe periphery. The instrument employs an array of high frequency steered
transducers, which are mounted on six pads. The instrument is capable of logging in casing sizes from 4.5 inches to 13 3/8 inches with any type of fluid or gas occupying the borehole. A 5-foot omnidirectional transmitter-receiver span is provided for Signature or Variable Density display. The Segmented Bond Tool (SBT) examines not only the longitudinal cement quality, but also the circumferential effectiveness of the cement sheath radially around the entire periphery of the casing.

CEMENT BOND LOGGING

GENERAL INSTRUCTIONS

I. Tool Centralization

A. Minimum of three centralizers.

B. Preferably bow spring or rigid aluminum centralizers.

C. Position centralizers immediately above and below transmitter-receiver section and on top of tool assembly.

II. Well Data

A. Well name, location, serial number (if any).

B. Data on cement, including type, volume, time, whether pipe was reciprocated or rotated or both, etc.

C. Casing scratcher and centralizer depths.

D. Unique downhole conditions.

E. Casing data including size, weight, grade, joint type, depths. Well bore fluid data including type, weight, and salinity.

G. Bottom hole temperature.

H. Well history for maximum previous pressure on casing.

III. Calibration

Tool should have been calibrated at the company shop and the service company should perform surface calibration before running tool in hole. Each service company has their own calibration procedure. An example of one company's shop and well site calibration procedure is shown below:

<u>Shop Calibration</u>

A. The tool is centered inside a section of 5.5", 151b/ft casing; completely covered with water; the tank is pressured to 500 psi; the signal on the 3ft receiver is adjusted for a maximum output of 80mv.

B. Signal output of 5ft receiver is adjusted in order to compensate for energy loss related to the 3ft., due to the extended travel time of 114 microseconds.

C. Panels are calibrated for response and linearity .

D. A full display of calibration is recorded for every tool. Shop calibrations are required monthly or more frequently as needed. A copy of the shop calibration should be attached to the log.

Well Site Calibration

A. With tool in hole and in fluid, panel output is calibrated for a linear output relation of 100mv. for 10 chart divisions.-10 mv/div. This calibration is done in order to scale the amplitude values.

B. Secondary amplitude X4 or X5 is calibrated.

C. Internal calibration cycle of 35mv amplitude and 50 microseconds wavelength is activated; The gate is set on the cycle, and amplitude deflection is adjusted according to previous 0-100mv settings.

D. Calibration cycle is deactivated. Tool signal on 3 foot receiver is present; the gate is set on the first compressional cycle, and amplitude reading is verified.

IV. Complete Log Heading.

V. Run V DL, MSG, Signature, X-V plot on 200-1200 microsecond time scale.

VI. Run repeat sections (200' minimum) through intervals of interest or intervals with questionable bond.

VII. Logging speed should be 1800 feet/hr.

VII, If tool is improperly centralized, do not continue to log. Pullout of hole and adjust or replace centralizers.

IX. Upon completion of logging run, check surface calibration.

ACOUSTIC CEMENT BOND LOGGING

CHECK LISTS

INFORMATION REQUESTED PRIOR TO RUNNING CEMENT EVALUATION LOGS

I. CEMENT DATA.

A. Types, volumes, slurry weights, pumping rate.______________________

B. Estimated compressive strength.______________________

C. Date and time cementing operation was completed.______________________

D. Additives.______________________

E. A copy of Cementing Report would be helpful.______________________

II. ASSOCIATED CEMENTING PROBLEMS.

A. Lost circulation?______________________

B. Unable to reciprocate? Stuck pipe?______________________

C. Abnormal pressures held after plug down? How long?______________________

III. CASING INFORMATION.

A. All strings --- size, weight, grade, coupling (flush Joint?)______________________

B. Top/bottom depths --- overlaps? Annular thickness?______________________

C. Cementing aids ---scratchers, centralizers, hydrobonders -where?______________________

IV. WELL INFORMATION.

A. Straight hole or deviated? If deviated, at what depth? Degree?______________________

B. Bit size?______________________

C. Wellbore fluid? Accurate density? Same as plug down fluid?______________________

D. Casing problems? Liner not set? Potential for gas cut fluid?______________________

E. Open perforations? Unable to pressure up?____________________

F. Wellhead connection required? Need pump-in sub?________________

G. Any previous cement analysis done? Temperature logs?______________

~~H. Ensure open Hole Logs available at well site.~~____________________

I. Has coated casing been run in well?__________________________

J. Squeeze guns brought w/CBL?______________________________

CBL LOG QUALITY CHECKS

I. FREE PIPE

A. Transit time Indicating correct expected value for casing size and weight?_____

B. Transit time, magnetic collar locator, amplitude curve and variable density/waveform all Indicating. Casing collars on depth with each other?_______

C. Free pipe amplitude reading correct value for casing size and weight?__________

D. E1 arrival on variable density display indicating correct transit time to 5 foot receiver, (i.e. 114 microseconds later than 3 foot transit time)?_______________

E. Collars on amplitude curve are 3foot in vertical height and 5 foot high on VDL. This ensures amplitude and VDL/WF are measured on proper receiver._______

II. CEMENTED INTERVAL

A. Transit time stretching or cycle skipping occurring in Well Bonded Sections?____

B. 100% and 70% bonded Intervals consistent with minimum Sonic amplitude picked from CBL Interpretation chart?________________________________

C. Is transit time less than free pipe value Indicating eccentering or fast formation?___

D. If eccentering is expected, check V DL for Chevron pattern at collars and low CBL amplitudes.____________________________

E. If fast formation is suspected, i.e. open hole logs indicate ~T less than 57 microseconds per foot, check 1st formation arrival on VDL/WF. If less than expected free pipe value on 5foot receiver, fast formation can be confirmed. Note: pre-log planning will let .us know whether fast formations are expected.______

F. Have log passes been run under sufficient pressure to eliminate Micro annulus effect?____

G. Does main log pass agree with repeat section?____________________________

H. Is main log pass properly correlated to open hole log? Note: if perforations are picked from a pressure pass make sure field personnel are aware of this and that proper correlation is taken into account prior to perforating.______________

APPENDIX E

(GUIDANCE - TEMPERATURE LOG)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

TEMPERATURE LOGGING FOR MECHANICAL INTEGRITY

January 12, 1999

PURPOSE:

The purpose of this document is to provide a guideline for the acquisition of temperature surveys, a procedure that may be used to determine the internal mechanical integrity of tubing and casing in an injection well. A temperature survey may be used to verify confinement of injected fluids within the injection formation.

Test results must be documented with service company or other appropriate (acceptable) records and/or charts, and the test should be witnessed by an EPA inspector. Arrangements may be made by contacting the EPA Region 8 Underground Injection Control (UIC) offices using the EPA toll-free number 1-800-227-8917 (ask for extension 6137 or 6155).

LOGGING PROCEDURE

Run the temperature survey while going into the hole, with the temperature sensor located as close to the bottom of the tool as possible. The tool need not be centralized.

Record temperatures a 1-5 °F per inch, on a 5 inches per 100 feet log scale.

Logging speed should be within 20 - 30 feet per minute.

Run the log from ground level to total depth (or plug-back depth) of the well.

When using digital logging equipment, use the highest digital sampling rate as possible. Filtering should be kept to a minimum so that small scale results are obtained and preserved.

Record the first log trace while injecting at up to the maximum allowed injection pressure. Subsequent to the temperature survey, the maximum injection pressure will be limited to the pressure used during the survey.

LOG TRACES

Log the first log trace while the well is actively injecting, and record traces for gamma ray, temperature, and differential temperature. Shut-in (not injecting) temperature curves should be recorded at intervals depending on the length of time that the injection well has been active. Preferred time intervals are shown in the following table:

Active Injection	Record Curves at These Times (In Hours)				
1 month	1	3	6	12	
6 months	1	6	10-122	22-24	
1 year	1	10-12	22-24	45-48	
5 years	1	10-12	22-24	45-48	90-96
10 years or more	1	22-24	45-48	90-96	186-192

H:\UIC\R8 UIC-Guidance\INFO-TempLog.wpd

APPENDIX F

(GUIDANCE FOR CONDUCTING A RADIOACTIVE TRACER SURVEY)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

RADIOACTIVE TRACER SURVEY

January 22, 1999

PURPOSE:

The purpose of this document is to provide a guideline for the acquisition of a radioactive tracer survey (RATS), a procedure that may be used to determine whether injected fluids may migrate vertically outside the casing after injection. This guidance may be used to develop a well-specific survey plan that accounts for specific well construction and operation considerations. Prior approval of planned RATS procedures by EPA is strongly recommended.

Radioactive Tracer Survey results must be documented with service company and other appropriate log records and/or charts, and the test should be witnessed by an EPA inspector. Arrangements may be made by contacting EPA Region 8 Underground Injection Control (UIC) offices using the EPA toll-free number 1-800-227-8917 (ask for extension 6155 or 6137).

RECORDING GUIDELINES

The logging must be done while the well is **injecting at normal injection pressure and rate**. The pressure and rate should be brought to equilibrium conditions prior to conducting the survey.

The survey tool must **include a collar locator** for depth control, an injector, and two detectors (one above and one below the injector).

Vertical **log scale** may be one inch, two inches, or five inches per 100 feet.

The Gamma Ray log may be run at up to 60 feet per minute (ft/min) at a time constant (TC) of one second, or up to 30 ft/min at a TC of 2 seconds, or up to 15 ft/min at a TC of 4 seconds. **The logging speed and time constant used must be indicated on the log heading.**

The **horizontal log scale** must be recorded in standard API Units (or in counts per second).

The **gamma ray (GR) sensitivity** must be set so that the tracer will be obvious when detected and will not be confused with normal "hot spots" in the logged formations (e.g., the gamma ray sensitivity set so that the lithology can be correlated by recording a "base log").

Record the beginning and ending clock times of each log pass.

Record the injection pressure and rate during each log pass.

Record the volume of fluid injected BETWEEN log passes.

Record the type, volume, and concentration of each tracer "slug" used.

Show the percentage of fluid loss across the perforated interval(s).

RECOMMENDED PROCEDURE:

With the GR sensitivity set for the lithologic correlation log as outlined above, run one "base log" from the injection zone to at least 500 feet above the injection zone (or at least 200 feet above the top of the confining zone).

Commence operating the well at normal operating injection pressure and rate, and continue to do so until the pressure and rate become stabilized.

Set the tool so that the injector is positioned just below the tubing packer and inject a "slug" of tracer.

Reduce the GR sensitivity enough to keep the entire slug of the tracer radiation within the width of the chart paper (horizontal scale). To do this, a non-recorded pass through the slug may be run.

Drop tool to an appropriate depth below the slug and record Log Pass #1. Log to above the upper interface until the radiation level returns to the same level as below the slug. Drop tool to the appropriate depth below the slug and record Log Pass # 2 in the same manner as #1.

Repeat log passes process until the tracer slug strength dissipates to one tenth (1/10) of original strength (on Log Pass #1). At this point, reset (increase) the GR sensitivity to the same settings used for the base log, and log from the injection zone to at least 500 feet above the injection zone (or at least 200 feet above the top of the confining zone).

Drop tool to an appropriate depth below the slug, reset (reduce) the GR sensitivity to that used for logging (same setting as Log Pass #1), and record a log pass up to the packer. Repeat this logging process until the tracer slug is gone or has completely stopped. Then reset (increase) the GR sensitivity back to the base log setting and make a final logging pass from the injection zone to at least 500 feet above the injection zone (or at least 200 feet above the top of the confining zone). This final pass should show a close similarity to the pre-test base log response. NOTE: More than one pass may be shown on a log segment as long as each separate GR curve with its corresponding collar locator are distinguishable, otherwise record each pass on a separate log segment.

Drop and set the tool at the depth where the bottom detector is just above the uppermost perforation and inject a slug of tracer (the tool remains stationary for this logging record). As the slug moves past the bottom detector, the log trace should show an increase in the GR response. Hold the tool at this depth while pumping at the equilibrium pressure and rate.

SUBMITTING THE RESULTS:

An interpretation of the logging results must be supplied when submitting the data for EPA approval. The interpretation must include a fluid loss profile across the perforations, in increments of at least 25%

Include a schematic diagram of the well construction on or with the log. The diagram should show the casing diameters and depths, tubing diameter and depth, perforated interval, any open hole intervals, tot depth or plugged back total depth, and the location of the tool when the slug was injected. Also, indicate with arrows the pathway(s) the tracer slug appears to have gone.

APPENDIX G

(GUIDANCE FOR CONDUCTING A PRESSURE TEST TO DETERMINE IF A WELL HAS LEAKS IN THE TUBING, CASING OR PACKER)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

SUBJECT: GROUND WATER SECTION GUIDANCE NO. 39
Pressure testing injection wells for Part I (internal) Mechanical Integrity

---

FROM: Tom Pike, Chief
UIC Direct Implementation Section

TO: All Section Staff
Montana Operations Office

Introduction

The Underground Injection Control (UIC) regulations require that an injection well have mechanical integrity at all times (40 CFR 144.28 (f)(2) and 40 CFR 144.51 (q)(1)). A well has mechanical integrity (40 CFR 146.8) if:

(1) There is no significant leak in the tubing, casing or packer; and

(2) There is no significant fluid movement into an underground source of drinking water (USDW) through vertical channels adjacent to the injection wellbore.

Definition: Mechanical Integrity Pressure Test for Part I. A pressure test used to determine the integrity of all the downhole components of an injection well, usually tubing,casing and packer. It is also used to test tubing cemented in the hole by using a tubing plug or retrievable packer. Pressure tests must be run at least once every five years. If for any reason the tubing/packer is pulled, the injection well is required to pass another mechanical integrity test of the tubing casing and packer prior to recommencing injection regardless of when the last test was conducted. Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded on either the attached form or an equivalent form containing the necessary information. A pressure recording chart documenting the actual annulus test pressures must be attached to the form.

This guidance addresses making a determination of Part I of Mechanical Integrity (no leaks in the tubing, casing or packer). The Region's policy is: 1) to determine if there are significant leaks in the tubing, casing or packer; 2) to assure that the casing can withstand pressure similar to that which would be applied if the tubing or packer fails; 3) to make the Region's test procedure consistent with the procedures utilized by other Region VIII Primacy programs; and 4) to provide a procedure which can be easily administered and is applicable to all class I and II wells. Although there are several methods allowed for determining mechanical integrity, the principal method involves running a pressure test of the tubing/casing annulus. Region VIII's procedure for running a pressure test is intended to aid UIC field inspectors who witness pressure tests for the purpose of demonstrating that a well has Part I of Mechanical Integrity. The guidance is also intended as a means of informing operators of the procedures required for conducting the test in the absence of an EPA inspector.

Pressure Test Description

Test Frequency

The mechanical integrity of an injection well must be maintained at all times. Mechanical integrity pressure tests are required at least every five (5) years. If for any reason the tubing/packer is pulled, however, the injection well is required to pass another mechanical integrity test prior to recommencing injection regardless of when the last test was conducted. The Regional UIC program must be notified of the workover and the proposed date of the pressure test. The well's test cycle would then start from the date of the new test if the well passes the test and documentation is adequate. Tests may be required on a more frequent basis depending on the nature of the injectate and the construction of the well (see Section guidance on MITs for wells with cemented tubing and regulations for Class I wells).

Region VIII's criteria for well testing frequency is as follows:

1. Class I hazardous waste injection wells; initially [40 CFR 146.68(d)(1)] and annually thereafter;

2. Class I non-hazardous waste injection wells; initially and every two (2) years thereafter, except for old permits (such as the disposal wells at carbon dioxide extraction plants which require a test at least every five years);

3. Class II wells with tubing, casing and packer; initially and at least every five (5) years thereafter;

4. Class II wells with tubing cemented in the hole; initially and every one (1) or two (2) years thereafter

depending on well specific conditions (See Region VIII UIC Section Guidance #36);

5. Class II wells which have been temporarily abandoned (TAd) must be pressure tested after being shut-in for two years; and

6. Class III uranium extraction wells; initially.

Test Pressure

To assure that the test pressure will detect significant leaks and that the casing is subjected to pressure similar to that which would be applied if the tubing or packer fails, the tubing/casing annulus should be tested at a pressure equal to the maximum allowed injection pressure or 1000 psig whichever is less. The annular test pressure must, however, have a difference of at least 200 psig either greater or less than the injection tubing pressure. Wells which inject at pressures of less than 300 psig must test at a minimum pressure of 300 psig, and the pressure difference between the annulus and the injection tubing must be at least 200 psi.

Test Criteria

1. The duration of the pressure test is 30 minutes.

2. Both the annulus and tubing pressures should be monitored and recorded every five (5) minutes.

3. If there is a pressure change of 10 percent or more from the initial test pressure during the 30 minute duration, the well has failed to demonstrate mechanical integrity and should be shut-in until it is repaired or plugged.

4. A pressure change of 10 percent or more is considered significant. If there is no significant pressure change in 30 minutes from the time that the pressure source is disconnected from the annulus, the test may be completed as passed.

Recordkeeping and Reporting

The test results must be recorded on the attached form. The annulus pressure should be recorded at five (5) minute intervals. Tests run by operators in the absence of an EPA inspector must be conducted according to these procedures and recorded on the attached form or an equivalent form and a pressure recording chart documenting the actual annulus test pressures must be attached to the submittal. The tubing pressure at the beginning and end of each test must be recorded. The volume of the annulus fluid bled back at the surface after the test should be measured and recorded on the form. This can be done by bleeding the annulus pressure off and discharging the associated fluid into a five gallon container. The volume information can be used to verify the approximate location of the packer.

Procedures for Pressure Test

1. Scheduling the test should be done at least two (2) weeks in advance.

2. Information on the well completion (location of the packer, location of perforations, previous cement work on the casing, size of casing and tubing, etc.) and the results of the previous MIT test should be reviewed by the field inspector in advance of the test. Regional UIC Guidance #35 should also be reviewed. Information relating to the previous MIT and any well workovers should be reviewed and taken into the field for verification purposes.

3. All Class I wells and Class II SWD wells should be shut-in prior to the test. A 12 to 24-hour shut-in is preferable to assure that the temperature of the fluid in the wellbore is stable.

4. Class II enhanced recovery wells may be operating during the test, but it is recommended that the well be shut-in if possible.

5. The operator should fill the casing/tubing annulus with inhibited fluid at least 24 hours in advance, if possible. Filling the annulus should be undertaken through one valve with the second valve open to allow air to escape. After the operator has filled the annulus, a check should be made to assure that the annulus will remain full. If the annulus can not maintain a full column of fluid, the operator should notify the Director and begin a rework. The operator should measure and report the volume of fluid added to the annulus. If not already the case, the casing/tubing valves should be closed, at least, 24 hours prior to the pressure test.

Following steps are at the well:

6. Read tubing pressure and record on the form. If the

well is shut-in, the reported information on the actual maximum operating pressure should be used to determine test pressures.

7. Read pressure on the casing/tubing annulus and record value on the form. If there is pressure on the annulus, it should be bled off prior to the test. If the pressure will not bleed-off, the guidance on well failures (Region VIII UIC Section Guidance #35) should be followed.

8. Ask the operator for the date of the last workover and the volume of fluid added to the annulus prior to this test and record information on the form.

9. Hook-up well to pressure source and apply pressure until test value is reached.

10. Immediately disconnect pressure source and start test time (If there has been a significant drop in pressure during the process of disconnection, the test may have to be restarted). The pressure gages used to monitor injection tubing pressure and annulus pressure should have a pressure range which will allow the test pressure to be near the mid-range of the gage. Additionally, the gage must be of sufficient accuracy and scale to allow an accurate reading of a 10 percent change to be read. For instance, a test pressure of 600 psi should be monitored with a 0 to 1000 psi gage. The scale should be incremented in 20 psi increments.

11. Record tubing and annulus pressure values every five (5) minutes.

12. At the end of the test, record the final tubing pressure.

13. If the test fails, check the valves, bull plugs and casing head close up for possible leaks. The well should be retested.

14. If the second test indicates a well failure, the Region should be informed of the failure within 24 hours by the operator, and the well should be shut-in within 48 hours per Headquarters guidance #76. A follow-up letter should be prepared by the operator which outlines the cause of the MIT failure and proposes a potential course of action. This report should be submitted to EPA within five days.

15. Bleed off well into a bucket, if possible, to obtain a volume estimate. This should be compared to the calculated value obtained using the casing/tubing annulus volume and fluid compressibility values.

16. Return to office and prepare follow-up.

Alternative Test Option

While it is expected that the test procedure outlined above will be applicable to most wells, the potential does exist that unique circumstances may exist for a given well that precludes or makes unsafe the application of this test procedure. In the event that these exceptional or extraordinary conditions are encountered, the operator has the option to propose an alternative test or monitoring procedures. The request must be submitted by the operator in writing and must be approved in writing by the UIC-Implementation Section Chief or equivalent level of management.

Attachment

APPENDIX H

(GUIDANCE FOR CONDUCTING A STEP-RATE TEST)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION VIII
999 18th STREET - SUITE 500
DENVER, COLORADO 80202-2466

STEP-RATE TEST PROCEDURE

January 12, 1999

PURPOSE:

The purpose of this document is to provide a guideline for the acquisition of a Step Rate Test (SRT). These procedures are consistent with acceptable oilfield practices. Test results may be used by the EPA to determine a Maximum Surface Injection Pressure (MSIP) to provide for the protection of the underground sources of drinking water at an injection well having mechanical integrity. Attached is a form that you may copy and use to record step rate test data.

Step rate test results must be documented with service company or other appropriate (acceptable) records and/or charts, and the test should be witnessed by an EPA inspector. Arrangements may be made by contacting the EPA Region 8 Underground Injection Control (UIC) offices using the EPA toll-free number 1-800-227-8917 (ask for extension 6137 or 6155).

STEP-RATE TEST PROCEDURE:

1). The well should be shut in long enough prior to testing such that the bottom hole pressures approximate shut-in formation pressures. If the shut-in well flows to the surface, the wellhead injection string should be equipped with a gauge and the static surface pressure read and recorded.

2) A series of successively higher injection rates are determined using guidelines below, and the elapsed time and pressure values are read and recorded for each rate and time step. Each rate step should last <u>exactly</u> as long as the preceding rate. If stabilized pressure values are not obtained within the rate steps suggested below, the test results may be inconclusive.

Formation Permeability (md)	*Total time per rate-step (min)*
≤ 5 md	60 min
≥ 10 md	30 min

3) Suggested injection rates:

5%
10%
20%
40% } Of Anticipated Maximum Injection Rate
60%
80%
100%

4) Injection rates should be controlled with a constant flow regulator that has been tested prior to use. A throttling device is not sufficient.

5) Flow rates should be measured with a calibrated turbine flowmeter.

6) Record injection rates using a chart recorder or a strip chart.

7) Measure pressures with a down hole pressure bomb.

8) Measure and record injection pressures with a gauge or recorder (for immediate test results).

9) A plot of injection rates and the corresponding stabilized pressure values should be graphically represented as a constant slope straight line to a point at which the formation fracture, or "breakdown", pressure is exceeded. The slope of this subsequent straight line should be less than that of the before-fracture straight line.

10) If the formation fracture pressure has definitely been exceeded, evidenced by at least two injection rate-pressure combinations greater than the breakdown pressure, the injection pump should be stopped, the line valve closed, and the pressure is allowed to bleed-off into the injection formation. There will occur a significant instantaneous pressure drop (Instantaneous Shut-in Pressure or ISIP), after which the pressure values begin to level out. This ISIP value must be read and recorded. The ISIP obtained in this manner may be considered to be the minimum pressure required to hold open a fracture in this formation at this well.

11) Once the ISIP is obtained, the SRT is concluded.

12) In the event that the breakdown pressure was not obtained at the maximum test injection pressure utilized, the test results may indicate that the formation is accepting fluids without fracturing.

STEP RATE TEST DATA

Well: ____________________ Date: __________ Operator ____________________

STEP #1 Test Rate (5% of maximum rate) __________ (bbl/min)

Time (min) : ______ ______ ______ ______ ______ ______ ______

Pressure (psi): ______ ______ ______ ______ ______ ______ ______

STEP #2 Test Rate (10% of maximum rate) __________ (bbl/min)

Time (min) : ______ ______ ______ ______ ______ ______ ______

Pressure (psi): ______ ______ ______ ______ ______ ______ ______

STEP #3 Test Rate (20% of maximum rate) __________ (bbl/min)

Time (min) : ______ ______ ______ ______ ______ ______ ______

Pressure (psi): ______ ______ ______ ______ ______ ______ ______

STEP #4 Test Rate (40% of maximum rate) __________ (bbl/min)

Time (min) : ______ ______ ______ ______ ______ ______ ______

Pressure (psi): ______ ______ ______ ______ ______ ______ ______

STEP #5 Test Rate (60% of maximum rate) __________ (bbl/min)

Time (min) : ______ ______ ______ ______ ______ ______ ______

Pressure (psi): ______ ______ ______ ______ ______ ______ ______

STEP #6 Test Rate (80% of maximum rate) __________ (bbl/min)

Time (min) : ______ ______ ______ ______ ______ ______ ______

Pressure (psi): ______ ______ ______ ______ ______ ______ ______

STEP #7 Test Rate (100% of maximum rate) __________ (bbl/min)

Time (min) : ______ ______ ______ ______ ______ ______ ______

Pressure (psi): ______ ______ ______ ______ ______ ______ ______

ISIP : ____________________ (psi)

Test Run / Witnessed By: ____

EXAMPLE STEP RATE TEST

The following is an example of a Step-Rate Test with tabular and graphic results. The step-rate test data and graphic results of the test are on the following pages.

The operator of Anywell #1 set up a SRT for the following conditions:

A) Maximum anticipated injection rate was 4 bbl/min.

B) Following the recommended test procedures, the operator planned on using these rates for the test:

1) 5% of 4 bbl/min = 0.2 bbl/min

2) 10% of 4 bbl/min = 0.4 bbl/min

3) 20% of 4 bbl/min = 0.8 bbl/min

4) 40% of 4 bbl/min = 1.6 bbl/min

5) 60% of 4 bbl/min = 2.4 bbl/min

6) 80% of 4 bbl/min = 3.2 bbl/min

7) 100% of 4 bbl/min = 4.0 bbl/min

C) The formation permeability is estimated as 100 md, therefore each step will last for 30 minutes.

For this test, the injection formation broke down at approximately 1200 psi, and the ISIP was listed as 1000 psi.

Because the injection formation will part at 1000 psi, the maximum injection pressure will be held to the ISIP. If the formation had not broken down at 1200 psi, the maximum allowable injection pressure would be the maximum pressure obtained during the test.

EXAMPLE STEP RATE TEST DATA

Well: ANYWELL #1 Date: 8/31/94 Operator Lotsa Oil Company

STEP #1 Test Rate (5% of maximum rate) 0.2 (bbl/min)

Time (min):	0	5	10	15	20	25	30
Pressure (psi):	0	90	95	98	99	100	100

STEP #2 Test Rate (10% of maximum rate) 0.4 (bbl/min)

Time (min):	0	5	10	15	20	25	30
Pressure (psi):	80	170	185	195	199	200	200

STEP #3 Test Rate (20% of maximum rate) 0.8 (bbl/min)

Time (min):	0	5	10	15	20	25	30
Pressure (psi):	190	325	385	392	398	399	400

STEP #4 Test Rate (40% of maximum rate) 1.6 (bbl/min)

Time (min):	0	5	10	15	20	25	30
Pressure (psi):	380	700	790	792	795	798	802

STEP #5 Test Rate (60% of maximum rate) 2.4 (bbl/min)

Time (min):	0	5	10	15	20	25	30
Pressure (psi):	750	990	1030	1090	1150	1180	1201

STEP #6 Test Rate (80% of maximum rate) 3.2 (bbl/min)

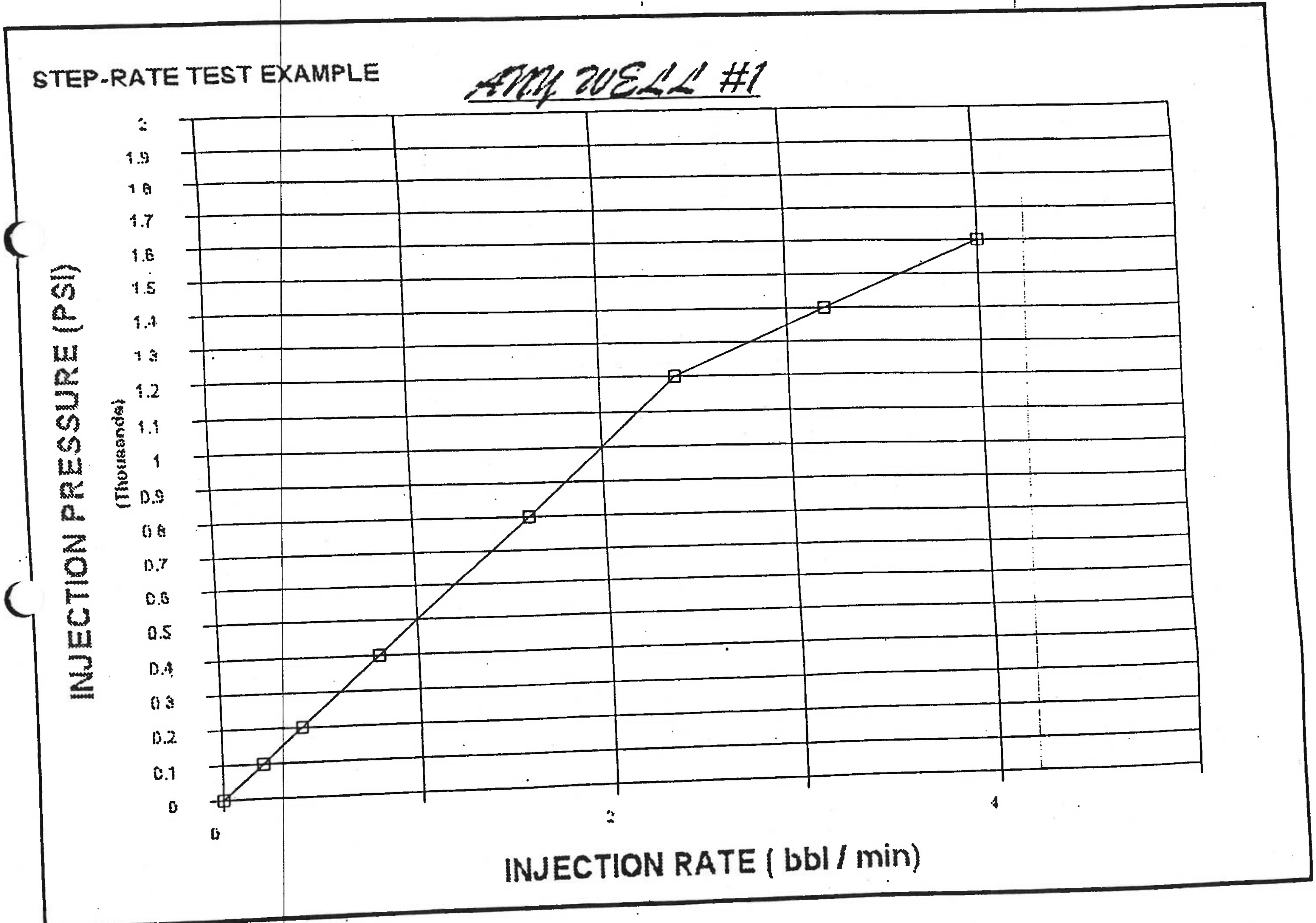
Time (min):	0	5	10	15	20	25	30
Pressure (psi):	1100	1250	1326	1370	1390	1395	1400

STEP #7 Test Rate (100% of maximum rate) 4.0 (bbl/min)

Time (min):	0	5	10	15	20	25	30
Pressure (psi):	1350	1450	1500	1530	1570	1590	1600

ISIP : 1000 (psi)

Alan Testor



STEP-RATE TEST EXAMPLE
ANY WELL #1
INJECTION PRESSURE (PSI)
(Thousands)
2
1.9
1.8
1.7
1.6
1.5
1.4
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
2
4
INJECTION RATE (bbl / min)

APPENDIX I

(GUIDANCE FOR CONDUCTING A PRESSURE FALLOFF TEST)

EPA Region 6

UIC PRESSURE FALLOFF TESTING GUIDELINE

Third Revision

August 8, 2002

TABLE OF CONTENTS

APPENDIX

EPA Region 6

UIC PRESSURE FALLOFF TESTING GUIDELINE

Third Revision
August 8, 2002

1.0 Background

The Hazardous and Solid Waste Amendments of 1984 to the Resource Conservation and Recovery Act mandated prohibitions on the land disposal of hazardous waste. These prohibitions are known as the land disposal restrictions and EPA promulgated regulations to implement these requirements for injection wells on July 26, 1988. The land disposal restrictions for injection wells are codified in 40 CFR Part 148. In addition to specifying the effective dates of the restrictions on injection of specific hazardous wastes, these regulations outline the requirements for obtaining an exemption to the restrictions.

Facilities that have received an exemption to the land disposal restrictions under 40 CFR Part 148 have demonstrated that, to a reasonable degree of certainty, there will be no migration of hazardous constituents from the injection zone for as long as the waste remains hazardous. As part of this approval, facilities are required by Region 6 to meet approval conditions including annual monitoring in accordance with 40 CFR 148.20(d)(2).

Region 6 has adopted the 40 CFR 146.68(e)(1) requirements for monitoring Class 1 hazardous waste disposal wells. Under 40 CFR 146.68(e)(1), operators are required annually to monitor the pressure buildup in the injection zone, including at a minimum, a shut down of the well for a time sufficient to conduct a valid observation of the pressure falloff curve.

A falloff test is a pressure transient test that consists of shutting in an injection well and measuring the pressure falloff. The falloff period is a replay of the injection preceding it; consequently, it is impacted by the magnitude, length, and rate fluctuations of the injection period. Falloff testing analysis provides transmissibility, skin factor, and well flowing and static pressures. All of these parameters are critical for evaluation of technical adequacy of no migration demonstrations and UIC permits.

2.0 Purpose of Guideline

This guideline has been developed by the Region 6 office of the Evironmental Protection Agency (EPA) to assist operators in planning and conducting the falloff test and preparing the annual monitoring report. Typically, this report should consist of a falloff test and a comparison of the reservoir parameters derived from the test with those of the petition demonstration. Falloff tests provide reservoir pressure data and characterize both the injection interval reservoir and the completion condition of the injection well. Both the reservoir parameters and pressure data are necessary for no migration and UIC permit demonstrations. Additionally, a valid falloff test is a requirement of a no migration petition condition as well as a monitoring requirement under 40 CFR Part 146 for all Class I injection wells. For no migration purposes, the annual report is viewed not as an enforcement tool, but as an annual confirmation that the petition demonstration continues to be valid.

The main body of this guideline contains general information that pertains to the majority of the facilities impacted. Because each site is unique, one guideline cannot be written to encompass all situations. A more detailed discussion of many topics and equations is included in the attached Appendix.

The ultimate responsibility of conducting a valid falloff test is the task of the operator. Operators should QA/QC the pressure data and test results to confirm that the results "make sense" prior to submission of the report to the EPA for review.

3.0 Timing of Falloff Tests and Report Submission

Falloff tests must be conducted within one year from the date of the original petition approval and annually thereafter. The time interval for each test should not be less than 9 months or greater than 15 months from the previous test. This will ensure that the tests will be performed at relatively even intervals throughout the duration of the petition approval period. Operators can, at their discretion, plan these tests to coincide with the performance of their annual state MIT requirements as long as the time requirements are met. The falloff testing report should be submitted no later than 60 days following the test. Failure to submit a falloff test report will be considered a violation of the applicable petition condition and may result in an enforcement action. Any exceptions should be approved by EPA prior to conducting the test.

4.0 Falloff Test Report Requirements

In general, the report to EPA should provide general information and an overview of the falloff test, an analysis of the pressure data obtained during the test, a summary of the test results, and a comparison of the results with the parameters used in the no migration demonstration. Some of the following operator and well data will not change so once acquired, it can be copied and submitted with each annual report. The falloff test report should include the following information:

1. Company name and address
2. Test well name and location
3. The name and phone number of the facility contact person. The contractor contact may be included if approved by the facility <u>in addition</u> to a facility contact person.

4. A photocopy of an openhole log (SP or Gamma Ray) through the injection interval illustrating the type of formation and thickness of the injection interval. The entire log is not necessary.
5. Well schematic showing the current wellbore configuration and completion information:
   - Wellbore radius
   - Completed interval depths
   - Type of completion (perforated, screen and gravel packed, openhole)
6. Depth of fill depth and date tagged.
7. Offset well information:
   - Distance between the test well and offset well(s) completed in the same interval or involved in an interference test
   - Simple illustration of locations of the injection and offset wells
8. Chronological listing of daily testing activities.
9. Electronic submission of the raw data (time, pressure, and temperature) from <u>all</u> pressure gauges utilized on a floppy disk or CD-ROM. A READ.ME file or the disk label should list all files included and any necessary explanations of the data. A separate file containing any edited data used in the analysis can be submitted as an additional file.
10. Tabular summary of the injection rate or rates preceding the falloff test. At a minimum, rate information for 48 hours prior to the falloff or for a time equal to twice the time of the falloff test is recommended. If the rates varied and the rate information is greater than 10 entries, the rate data should be submitted electronically as well as a hard copy of the rates for the report. Including a rate vs time plot is also a good way to illustrate the magnitude and number of rate changes prior to the falloff test.
11. Rate information from any offset wells completed in the same interval. At a minimum, the injection rate data for the 48 hours preceding the falloff test should be included in a tabular and electronic format. Adding a rate vs time plot is also helpful to illustrate the rate changes.
12. Hard copy of the time and pressure data analyzed in the report.
13. Pressure gauge information: (See Appendix, page A-1 for more information on pressure gauges)
   - List all the gauges utilized to test the well
   - Depth of each gauge
   - Manufacturer and type of gauge. Include the full range of the gauge.
   - Resolution and accuracy of the gauge as a % of full range.
   - Calibration certificate and manufacturer's recommended frequency of calibration
14. General test information:
   - Date of the test
   - Time synchronization: A specific time and date should be synchronized to an equivalent time in each pressure file submitted. Time synchronization should also be provided for the rate(s) of the test well and any offset wells.
   - Location of the shut-in valve (e.g., note if at the wellhead or number of feet from the wellhead)

15. Reservoir parameters (determination):
- Formation fluid viscosity, μ_f cp (direct measurement or correlation)
- Porosity, ϕ fraction (well log correlation or core data)
- Total compressibility, c_t psi^{-1} (correlations, core measurement, or well test)
- Formation volume factor, rvb/stb (correlations, usually assumed 1 for water)
- Initial formation reservoir pressure - See Appendix, page A-1
- Date reservoir pressure was last stabilized (injection history)
- Justified interval thickness, h ft - See Appendix, page A-15

16. Waste plume:
- Cumulative injection volume into the completed interval
- Calculated radial distance to the waste front, r_{waste} ft
- Average historical waste fluid viscosity, if used in the analysis, μ_{waste} cp

17. Injection period:
- Time of injection period
- Type of test fluid
- Type of pump used for the test (e.g., plant or pump truck)
- Type of rate meter used
- Final injection pressure and temperature

18. Falloff period:
- Total shut-in time, expressed in real time and Δt, elapsed time
- Final shut-in pressure and temperature
- Time well went on vacuum, if applicable

19. Pressure gradient:
- Gradient stops - for depth correction

20. Calculated test data: include all equations used and the parameter values assigned for each variable within the report
- Radius of investigation, r_i ft
- Slope or slopes from the semilog plot
- Transmissibility, kh/μ md-ft/cp
- Permeability (range based on values of h)
- Calculation of skin, s
- Calculation of skin pressure drop, ΔP_{skin}
- Discussion and justification of any reservoir or outer boundary models used to simulate the test
- Explanation for any pressure or temperature anomaly if observed

21. Graphs:
- Cartesian plot: pressure and temperature vs. time
- Log-log diagnostic plot: pressure and semilog derivative curves. Radial flow regime should be identified on the plot
- Semilog and expanded semilog plots: radial flow regime indicated and the semilog straight line drawn
- Injection rate(s) vs time: test well and offset wells (not a circular or strip chart)

22. A comparison of all parameters with those used in the petition demonstration, including references where the parameters can be found in the petition.

23. A copy of the latest radioactive tracer run to fulfill the annual mechanical integrity testing requirement for the State and a brief discussion of the results.
24. Compliance with any unusual petition approval conditions such as the submission of an annual flow profile survey. These additional conditions may be addressed either in the annual falloff testing report or in an accompanying document.

5.0 Planning

The radial flow portion of the test is the basis for all pressure transient calculations. Therefore the injectivity and falloff portions of the test should be designed not only to reach radial flow, but to sustain a time frame sufficient for analysis of the radial flow period.

General Operational Concerns

Successful well testing involves the consideration of many factors, most of which are within the operator's control. Some considerations in the planning of a test include:

- Adequate storage for the waste should be ensured for the duration of the test
- Offset wells completed in the same formation as the test well should be shut-in, or at a minimum, provisions should be made to maintain a constant injection rate prior to and during the test
- Install a crown valve on the well prior to starting the test so the well does not have to be shut-in to install a pressure gauge
- The location of the shut-in valve on the well should be at or near the wellhead to minimize the wellbore storage period
- The condition of the well, junk in the hole, wellbore fill or the degree of wellbore damage (as measured by skin) may impact the length of time the well must be shut-in for a valid falloff test. This is especially critical for wells completed in relatively low transmissibility reservoirs or wells that have large skin factors.
- Cleaning out the well and acidizing may reduce the wellbore storage period and therefore the shut-in time of the well
- Accurate recordkeeping of injection rates is critical including a mechanism to synchronize times reported for injection rate and pressure data. The elapsed time format usually reported for pressure data does not allow an easy synchronization with real time rate information. Time synchronization of the data is especially critical when the analysis includes the consideration of injection from more than one well.
- Any unorthodox testing procedure, or any testing of a well with known or anticipated problems, should be discussed with EPA staff prior to performing the test.
- Other pressure transient tests may be used in conjunction or in place of a falloff test in some situations. For example, if surface pressure measurements must be used because of a corrosive wastestream and the well will go on vacuum following shut-in, a multi-rate test may be used so that a positive surface pressure is maintained at the well.

- If more than one well is completed into the same reservoir, operators are encouraged to send at least two pulses to the test well by way of rate changes in the offset well following the falloff test. These pulses will demonstrate communication between the wells and, if maintained for sufficient duration, they can be analyzed as an interference test to obtain interwell reservoir parameters.

Site Specific Pretest Planning

1. Determine the time needed to reach radial flow during the injectivity and falloff portions of the test:
   - Review previous welltests, if available
   - Simulate the test using measured or estimated reservoir and well completion parameters
   - Calculate the time to the beginning of radial flow using the empirically-based equations provided in the Appendix. The equations are different for the injectivity and falloff portions of the test with the skin factor influencing the falloff more than the injection period. (See Appendix, page A-4 for equations)
   - Allow adequate time beyond the beginning of radial flow to observe radial flow so that a well developed semilog straight line occurs. A good rule of thumb is 3 to 5 times the time to reach radial flow to provide adequate radial flow data for analysis.

2. Adequate and consistent injection fluid should be available so that the injection rate into the test well can be held constant prior to the falloff. This rate should be high enough to produce a measurable falloff at the test well given the resolution of the pressure gauge selected. The viscosity of the fluid should be consistent. Any mobility issues (k/μ) should be identified and addressed in the analysis if necessary.

3. Bottomhole pressure measurements are usually superior to surface pressure measurements because bottomhole measurements tend to be less noisy. Surface pressure measurements can be used if positive pressure is maintained at the surface throughout the falloff portion of the test. The surface pressure gauge should be located at the wellhead. A surface pressure gauge may also serve as a backup to a downhole gauge and provide a monitoring tool for tracking the test progress. Surface gauge data can be plotted during the falloff in a log-log plot format with the pressure derivative function to determine if the test has reached radial flow and can be terminated. Note: Surface pressure measurements are not adequate if the well goes on a vacuum during the test. (See Appendix, page A-2 for additional information concerning pressure gauge selection.)

4. Use two pressure gauges during the test with one gauge serving as a backup, or for verification in cases of questionable data quality. The two gauges do not need to be the same type. (See Appendix, page A-1 for additional information concerning pressure gauges.)

6.0 Conducting the Falloff Test

1. Tag and record the depth to any fill in the test well

2. Simplify the pressure transients in the reservoir
   - Maintain a constant injection rate in the test well prior to shut-in. This injection rate should be high enough and maintained for a sufficient duration to produce a measurable pressure transient that will result in a valid falloff test.
   - Offset wells should be shut-in prior to and during the test. If shut-in is not feasible, a constant injection rate should be recorded and maintained during the test and then accounted for in the analysis.
   - Do not shut-in two wells simultaneously or change the rate in an offset well during the test.

3. The test well should be shut-in <u>at the wellhead</u> in order to minimize wellbore storage and afterflow. (See Appendix, page A-3 for additional information.)

4. Maintain accurate rate records for the test well and any offset wells completed in the same injection interval.

5. Measure and record the viscosity of the injectate periodically during the injectivity portion of the test to confirm the consistency of the test fluid.

7.0 Evaluation of the Falloff Test

1. Prepare a Cartesian plot of the pressure and temperature versus real time or elapsed time.
   - Confirm pressure stabilization prior to shut-in of the test well
   - Look for anomalous data, pressure drop at the end of the test, determine if pressure drop is within the gauge resolution

2. Prepare a log-log diagnostic plot of the pressure and semilog derivative. Identify the flow regimes present in the welltest. (See Appendix, page A-6 for additional information.)
   - Use the appropriate time function depending on the length of the injection period and variation in the injection rate preceding the falloff (See Appendix, page A-10 for details on time functions.)
   - Mark the various flow regimes - particularly the radial flow period
   - Include the derivative of other plots, if appropriate (e.g., square root of time for linear flow)
   - If there is no radial flow period, attempt to type curve match the data

3. Prepare a semilog plot.
   - Use the appropriate time function depending on the length of injection period and injection rate preceding the falloff
   - Draw the semilog straight line through the radial flow portion of the plot and obtain the slope of the line
   - Calculate the transmissibility, kh/μ
   - Calculate the skin factor, s, and skin pressure drop, ΔP_{skin}
   - Calculate the radius of investigation, r_i

4. Explain any anomalous results.

8.0 Comparison of Falloff Results to No Migration Petition Data

A comparison between the falloff test results and the parameters used in the no migration petition demonstration should be made. Specifically, the following should be demonstrated:

- Both the flowing and static bottom hole pressures measured during the test should be corrected for skin and be at or below those which were predicted to occur by the pressure buildup model in the approvided no migration petition for the same point in time. (See Appendix, page A-13)

- It should be shown that the (kh/μ) parameter group calculated from the current falloff data is the same or greater than that employed in the pressure buildup modeling.

9.0 Technical References

1. SPE Textbook Series No. 1, "Well Testing," 1982, W. John Lee
2. SPE Monograph 5, "Advances in Well Test Analysis," 1977, Robert Earlougher, Jr.
3. SPE Monograph 1, "Pressure Buildup and Flow Tests in Wells," 1967, C.S. Matthews and D.G. Russell
4. "Well Test Interpretation In Bounded Reservoirs," Hart's Petroleum Engineer International, Spivey, and Lee, November 1997
5. "Derivative of Pressure: Application to Bounded Reservoir Interpretation," SPE Paper 15861, Proano, Lilley, 1986
6. "Well Test Analysis," Sabet, 1991
7. "Pressure Transient Analysis," Stanislav and Kabir, 1990
8. "Well Testing: Interpretation Methods," Bourdarot, 1996
9. "A New Method To Account For Producing Time Effects When Drawdown Type Curves Are Used To Analyze Pressure Buildup And Other Test Data," SPE Paper 9289, Agarwal, 1980

10. "Modern Well Test Analysis – A Computer-Aided Approach," Roland N. Horne, 1990
11. Exxon Monograph, "Well Testing in Heterogeneous Formations," Tatiana Streltsova, 1987
12. EPA Region 6 Falloff Guidelines
13. "Practical Pressure Gauge Specification Considerations In Practical Well Testing," SPE Paper No. 22752, Veneruso, Ehlig-Economides, and Petitjean, 1991
14. "Guidelines Simplify Well Test Interpretation," Oil and Gas Journal, Ehlig-Economides, Hegeman, and Vik, July 18, 1994
15. Oryx Energy Company, Practical Pressure Transient Testing, G. Lichtenberger and K. Johnson, April 1990 (Internal document)
16. Pressure-Transient Test Design in Tight Gas Formations, SPE Paper 17088, W.J. Lee, October 1987
17. "Radius-of-Drainage and Stabilization-Time Equations," Oil and Gas Journal, H.K. Van Poollen, Sept 14, 1964
18. "Effects of Permeability Anisotropy and Layering On Well Test Interpretation," Hart's Petroleum Engineer International, Spivey, Aly, and Lee, February 1998
19. "Three Key Elements Necessary for Successful Testing," Oil and Gas Journal, Ehlig-Economides, Hegeman, Clark, July 25, 1994
20. "Introduction to Applied Well Test Interpretation," Hart's Petroleum Engineer International, Spivey, and Lee, August 1997
21. "Recent Developments In Well Test Analysis," Hart's Petroleum Engineer International, Stewart, August 1997
22. "Fundamentals of Type Curve Analysis," Hart's Petroleum Engineer International, Spivey, and Lee, September 1997
23. "Identifying Flow Regimes In Pressure Transient Tests," Hart's Petroleum Engineer International, Spivey and Lee, October 1997
24. "Selecting a Reservoir Model For Well Test Interpretation," Hart's Petroleum Engineer International, Spivey, Ayers, Pursell,and Lee, December 1997
27. "Use of Pressure Derivative in Well-Test Interpretation," SPE Paper 12777, SPE Formation Evaluation Journal, Bourdet, Ayoub, and Pirard, June 1989
28. "A New Set of Type Curves Simplifies Well Test Analysis," World Oil, Bourdet, Whittle, Douglas, and Pirard, May 1983

APPENDIX

Initial Formation Reservoir Pressure from Falloff Testing

For use in the no migration demonstration pressure buildup modeling:

- Some predictive models calculate a pressure buildup while other models calculate a specific pressure based on an initial reservoir pressure assigned to the model. No wellbore skin should be assumed in the demonstration. Historical falloff flowing pressure data used for comparison with model results should be corrected for skin effects
- The initial pressure should represent the initial reservoir pressure prior to initiation of injection in the model.
- Direct bottomhole static measurements are best. If no measurements are available, or are questionable, attempt to correct static surface pressures to bottomhole conditions. Use site specific information if available. Alternatively, the facility can reference a technical paper that may discuss the initial pressure of the injection interval at another location in the same area or an initial static pressure measurement from an offset injection well.
- Review historical measured static pressures. The initial reservoir pressure should be lower than the measured static pressures following injection at the well.

For use in Cone of Influence (COI) calculations in both no migration demonstrations and UIC permits:

- P^* is the false extrapolated pressure obtained from the semilog straight line at a time of 1 hour and is often used as the average reservoir pressure
- P^* is only applicable for a new well in an infinite acting reservoir
- EPA Region 6 does not recommend using P^* for the average reservoir pressure. For long injection periods, P^* will differ significantly from $\overline{P}$, the average reservoir pressure
- Use the final shut-in pressure, if the well reaches radial flow, for the cone of influence calculation

Pressure Gauge Usage and Selection

<u>Usage</u>

- EPA recommends that two gauges be used during the test with one gauge serving as a backup.
- As a general rule, downhole pressure measurements are less noisy and are preferred. Surface pressure measurements can be employed if positive pressure is maintained at the surface throughout the test. Surface gauges are insufficient if the well goes on a vacuum.
- Surface pressure gauges may be impacted by the fluctuations in ambient temperature that can occur over the course of a normal day. If unchecked, this aspect of these gauges can result in erroneous pressure readings. Insulating the gauges appears to be an effective countermeasure for temperature fluctuations in many instances.

- A surface or bottomhole surface readout gauge (SRO) allows tracking of pressures in real time. Analysis of this data can be performed in the field to confirm that the well has reached radial flow prior to ending the test.
- The derivative function plotted on the log-log plot amplifies noise in the data, so the use of a good pressure recording device is critical for application of this curve.
- Mechanical gauges should be calibrated before and after each test using a dead weight tester.
- Electronic gauges should also be calibrated according to the manufacturer's recommendations. The manufacturer's recommended frequency of calibration, and a copy of the gauge calibration certificate should be provided with the falloff testing report demonstrating this practice has been followed.

Selection

- The pressures must remain within the range of the pressure gauge. The larger percent of the gauge range utilized in the test, the better. Typical pressure gauge limits are 2000, 5000, and 10000 psi. Note that gauge accuracy and resolution are typically a function of percent of the full gauge range.
- Electronic downhole gauges generally offer much better resolution and sensitivity than a mechanical gauge but cost more. Additionally, the electronic gauge can generally run for a longer period of time, be programmed to measure pressure more frequently at various intervals for improved data density, and store data in digital form.
- Resolution of the pressure gauge must be sufficient to measure small pressure changes at the end of the test.
- The type of wastestream injected may prevent the use of a downhole gauge unless brine from offsite is brought in and used for the test. This may be cost prohibitive.

Test Design

General Operational Considerations

- The injection period controls what is seen on the falloff since the falloff is replay of the injection period. Therefore, the injection period must reach radial flow prior to shut-in of the well in order for the falloff test to reach radial flow

- Ideally to determine the optimal lengths of the injection and falloff periods, the test should be simulated using measured or estimated reservoir parameters. Alternatively, injection and falloff period lengths can be estimated from empirical equations using assumed reservoir and well parameters.

- The injection rate dictates the pressure buildup at the injection well. The pressure buildup from injection must be sufficient so that the pressure change during radial flow, usually occurring toward the end of the test, is large enough to measure with the pressure gauge selected.

- Waste storage and other operational issues require preplanning and need to be addressed prior to the test date. If brine must be brought in for the injection portion of the test, operators should insure that the fluid injected has a consistent viscosity and that there is adequate fluid available to obtain a valid falloff test. The use of the wastestream as the injection fluid affords several distinct advantages:
  1. Brine does not have to be purchased or stored prior to use.
  2. Onsite waste storage tanks may be used.
  3. Plant wastestreams are generally consistent, i.e., no viscosity variations

- Rate changes cause pressure transients in the reservoir. Constant rate injection in the test well and any offset wells completed in the same reservoir are critical to simplify the pressure transients in the reservoir. Any significant injection rate fluctuations at the test well or offsets must be recorded and accounted for in the analysis using superposition.

- Unless an injectivity test is to be conducted, shutting in the well for an extend period of time prior to conducting the falloff test reduces the pressure buildup in the reservoir and is not recommended.

- Prior to conducting a test, a crown valve should be installed on the wellhead to allow the pressure gauge to be installed and lowered into the well without any interruption of the injection rate.

- The wellbore schematic should be reviewed for possible obstructions located in the well that may prevent the use or affect the setting depth of a downhole pressure gauge. The fill depth in the well should also be reported. The fill depth may not only impact the depth of the gauge, but usually prolongs the wellbore storage period and depending on the type of fill, may limit the interval thickness by isolating some of the injection intervals. A wellbore cleanout or stimulation may be needed prior to conducting the test for the test to reach radial flow and obtain valid results.

- The location of the shut-in valve can impact the duration of the wellbore storage period. The shut-in valve should be located near the wellhead. Afterflow into the wellbore prolongs the wellbore storage period. The injection pipeline leading to the well can act as an extension to the well if the shut-in valve is not located near the wellhead. Operators should report the location of the shut-in valve and its distance from the wellhead, in the test report.

- The area geology should be reviewed prior to conducting the test to determine the thickness and type of formation being tested along with any geological features such as natural fractures, a fault, or a pinchout that should be anticipated to impact the test.

Wellbore and Reservoir Data Needed to Simulate or Analyze the Falloff Test

- Wellbore radius, r_w - from wellbore schematic
- Net thickness, h - See Appendix, page A-15
- Porosity, ϕ - log or core data
- Viscosity of formation fluid, μ_f - direct measurement or correlations
- Viscosity of waste, μ_{waste} - direct measurement or correlations
- Total system compressibility, c_t - correlations, core measurement, or well test
- Permeability, k - previous welltests or core data
- Specific gravity of injection fluid, s.g. - direct measurement
- Injection rate, q - direct measurement

Design Calculations

When simulation software is unavailable the test periods can be estimated from empirical equations. The following are set of steps to calculate the time to reach radial flow from empirically-derived equations:

1. Estimate the wellbore storage coefficient, C (bbl/psi). There are two equations to calculate the wellbore storage coefficient depending on if the well remains fluid filled (positive surface pressure) or if the well goes on a vacuum (falling fluid level in the well):

   a. Well remains fluid filled:

   $C = V_w \cdot c_{waste}$ where, V_w is the total wellbore volume, bbls
   c_{waste} is the compressibility of the injectate, psi^{-1}

   b. Well goes on a vacuum:

   $$C = \frac{V_u}{\dfrac{\rho \cdot g}{144 \cdot g_c}}$$ where, V_u is the wellbore volume per unit length, bbls/ft

   ρ is the injectate density, psi/ft
   g and g_c are gravitational constants

2. Calculate the time to reach radial flow for both the injection and falloff periods. Two different empirically-derived equations are used to calculate the time to reach radial flow, $t_{radial\ flow}$, for the injectivity and falloff periods:

   a. Injectivity period:

   $$t_{radial\ flow} > \frac{(200000 + 12000s) \cdot C}{\dfrac{k \cdot h}{\mu}} \ hours$$

   b. Falloff period:

   $$t_{radial\ flow} > \frac{170000 \cdot C \cdot e^{0.14 \cdot s}}{\dfrac{k \cdot h}{\mu}} \ hours$$

   The wellbore storage coefficient is assumed to be the same for both the injectivity and falloff periods. The skin factor, s, influences the falloff more than the injection period.

Use these equations with caution, as they tend to fall apart for a well with a large permeability or a high skin factor. Also remember, the welltest should not only reach radial flow, but also sustain radial flow for a timeframe sufficient for analysis of the radial flow period. As a rule of thumb, a timeframe sufficient for analysis is 3 to 5 times the time needed to reach radial flow.

3. As an alternative to steps 1 and 2, to look a specific distance "L" into the reservoir and possibly confirm the absence or existence of a boundary, the following equation can be used to estimate the time to reach that distance:

$$t_{boundary} = \frac{948 \cdot \phi \cdot \mu \cdot c_t \cdot L_{boundary}}{k} \quad hours$$

where, $L_{boundary}$ = feet to boundary
$t_{boundary}$ = time to boundary, hrs

Again, this is the time to reach a distance "L" in the reservoir. Additional test time is required to observe a fully developed boundary past the time needed to just reach the boundary. As a rule of thumb, to see a fully developed boundary on a log-log plot, allow at least 5 times the time to reach it. Additionally, for a boundary to show up on the falloff, it must first be encountered during the injection period.

4. Calculate the expected slope of the semilog plot during radial flow to see if gauge resolution will be adequate using the following equation:

$$m_{semi\log} = \frac{162.6 \cdot q \cdot \mathrm{B}}{\frac{k \cdot h}{\mu}}$$

where, q = the injection rate preceding the falloff test, bpd
B = formation volume factor for water, rvb/stb (usually assumed to be 1)

Considerations for Offset Wells Completed in the Same Interval

Rate fluctuations in offset wells create additional pressure transients in the reservoir and complicate the analysis. Always try to simplify the pressure transients in the reservoir. Do not simultaneously shut-in an offset well and the test well. The following items are key considerations in dealing with the impact of offset wells on a falloff test:

- Shut-in all offset wells prior to the test
- If shutting in offset wells is not feasible, maintain a constant injection rate prior to and during the test
- Obtain accurate injection records of offset injection prior to and during the test
- At least one of the real time points corresponding to an injection rate in an offset well should be synchronized to a specific time relating to the test well

- Following the falloff test in the test well, send at least two pulses from the offset well to the test well by fluctuating the rate in the offset well. The pressure pulses can confirm communication between the wells and can be simulated in the analysis if observed at the test well. The pulses can also be analyzed as an interference test using an Ei type curve.
- If time permits, conduct an interference test to allow evaluation of the reservoir without the wellbore effects observed during a falloff test.

Falloff Test Analysis

In performing a falloff test analysis, a series of plots and calculations should be prepared to QA/QC the test, identify flow regimes, and determine well completion and reservoir parameters. Individual plots, flow regime signatures, and calculations are discussed in the following sections.

<u>Cartesian Plot</u>

- The pressure data prior to shut-in of the well should be reviewed on a Cartesian plot to confirm pressure stabilization prior to the test. A well that has reached radial flow during the injectivity portion of the test should have a consistent injection pressure.

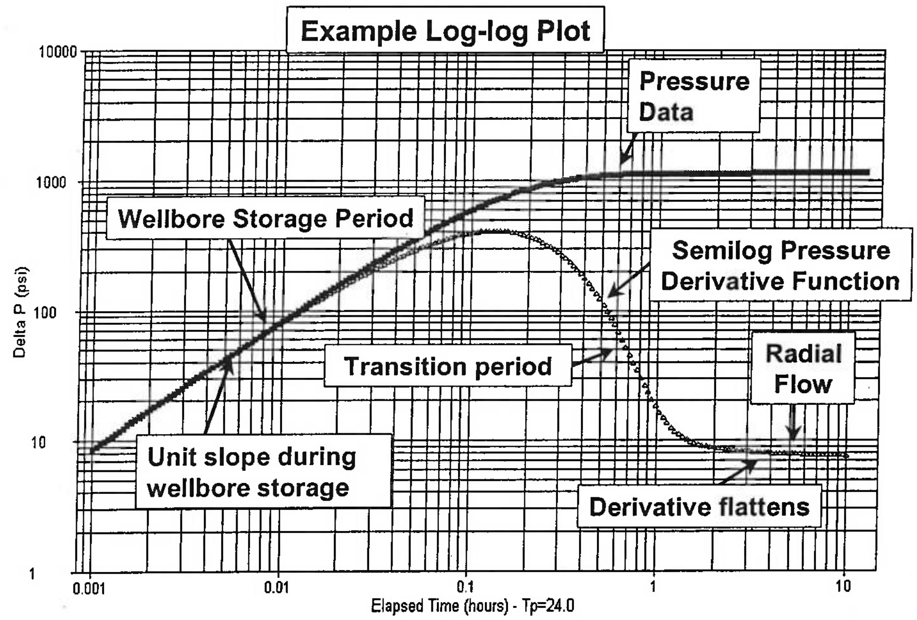
- A Cartesian plot of the pressure and temperature versus real time or elapsed time should be the first plot made from the falloff test data. Late time pressure data should be expanded to determine the pressure drop occurring during this portion of the test. The pressure changes should be compared to the pressure gauges used to confirm adequate gauge resolution existed throughout the test. If the gauge resolution limit was reached, this timeframe should be identified to determine if radial flow was reached prior to reaching the resolution of the pressure gauge. Pressure data obtained after reaching the resolution of the gauge should be treated as suspect and may need to be discounted in the analysis.

- Falloff tests conducted in highly transmissive reservoirs may be more sensitive to the temperature compensation mechanism of the gauge because the pressure buildup response evaluated is smaller. Region 6 has observed cases in which large temperature anomalies were not properly compensated for by the pressure gauge, resulting in erroneous pressure data and an incorrect analysis. For this reason, the Cartesian plot of the temperature data should be reviewed. Any temperature anomalies should be noted to determine if they correspond to pressure anomalies.

- Include the injection rate(s) of the test well 48 hours prior to shut-in on the Cartesian plot to illustrate the consistency of the injection rate prior to shut-in and to determine the appropriate time function to use on the log-log and semilog plots. (See Appendix, page A10 for time function selection)

Log-log Diagnostic Plot

- Plot the pressure and semilog derivative versus time on a log-log diagnostic plot. Use the appropriate time function based on the rate history of the injection period preceding the falloff. (See Appendix, page A-10 for time function selection) The log-log plot is used to identify the flow regimes present in the welltest. An example log-log plot is shown below:



Identification of Test Flow Regimes

- Flow regimes are mathematical relationships between pressure, rate, and time. Flow regimes provide a visualization of what goes on in the reservoir. Individual flow regimes have characteristic slopes and a sequencing order on the log-log plot.

- Various flow regimes will be present during the falloff test, however, not all flow regimes are observed on every falloff test. The late time responses correlate to distances further from the test well. The critical flow regime is radial flow from which all analysis calculations are performed. During radial flow, the pressure responses recorded are representative of the reservoir, not the wellbore.

- The derivative function amplifies reservoir signatures by calculating a running slope of a designated plot. The derivative plot allows a more accurate determination of the radial flow portion of the test, in comparison with the old method of simply proceeding 1½ log cycles from the end of the unit slope line of the pressure curve.

- The derivative is usually based on the semilog plot, but it can also be calculated based on other plots such as a Cartesian plot, a square root of time plot, a quarter root of time plot, and the 1/square root of time plot. Each of these plots are used to identify specific flow regimes. If the flow regime characterized by a specialized plot is present then when the derivative calculated from that plot is displayed on the log-log plot, it will appear as a "flat spot" during the portion of the falloff corresponding to the flow regime.

- Typical flow regimes observed on the log-log plot and their semilog derivative patterns are listed below:

Flow Regime	Semilog Derivative Pattern
Wellbore Storage	Unit slope
Radial Flow	Flat plateau
Linear Flow	Half slope
Bilinear Flow	Quarter slope
Partial Penetration	Negative half slope
Layering	Derivative trough
Dual Porosity	Derivative trough
Boundaries	Upswing followed by plateau
Constant Pressure	Sharp derivative plunge

Characteristics of Individual Test Flow Regimes

- Wellbore Storage:
  1. Occurs during the early portion of the test and is caused by the well being shut-in at the surface instead of the sandface
  2. Measured pressure responses are governed by well conditions and are not representative of reservoir behavior and are characterized by both the pressure and semilog derivative curves overlying a unit slope on the log-log plot
  3. Wellbore skin or a low permeability reservoir results in a slower transfer of fluid from the well to the formation, extending the duration of the wellbore storage period
  4. A wellbore storage dominated test is unanalyzable

- Radial Flow:
  1. The pressure responses are from the reservoir, not the wellbore
  2. The critical flow regime from which key reservoir parameters and completion conditions calculations are performed
  3. Characterized by a flattening of the semilog plot derivative curve on the log-log plot and a straight line on the semilog plot

- Spherical Flow:
  1. Identifies partial penetration of the injection interval at the wellbore
  2. Characterized by the semilog derivative trending along a negative half slope on the log-log plot and a straight line on the 1/square root of time plot
  3. The log-log plot derivative of the pressure vs 1/square root of time plot is flat

- Linear Flow
  1. May result from flow in a channel, parallel faults, or a highly conductive fracture
  2. Characterized by a half slope on both the log-log plot pressure and semilog derivative curves with the derivative curve approximately 1/3 of a log cycle lower than the pressure curve and a straight line on the square root of time plot.
  3. The log-log plot derivative of the pressure vs square root of time plot is flat

- Hydraulically Fractured Well
  1. Multiple flow regimes present including wellbore storage, fracture linear flow, bilinear flow, pseudo-linear flow, formation linear flow, and pseudo-radial flow
  2. Fracture linear flow is usually hidden by wellbore storage
  3. Bilinear flow results from simultaneous linear flows in the fracture and from the formation into the fracture, occurs in low conductivity fractures, and is characterized by a quarter slope on both the pressure and semilog derivative curves on the log-log plot and by a straight line on a pressure versus quarter root of time plot
  4. Formation linear flow is identified by a half slope on both the pressure and semilog derivative curves on the log-log plot and by a straight line on a pressure versus square root of time plot
  5. Psuedo-radial flow is analogous to radial flow in an unfractured well and is characterized by flattening of semilog derivative curve on the log-log plot and a straight line on a semilog pressure plot

- Naturally Fractured Rock
  1. The fracture system will be observed first on the falloff test followed by the total system consisting of the fractures and matrix.
  2. The falloff analysis is complex. The characteristics of the semilog derivative trough on the log-log plot indicate the level of communication between the fractures and the matrix rock.

- Layered Reservoir
  1. Analysis of a layered system is complex because of the different flow regimes, skin factors or boundaries that may be present in each layer.
  2. The falloff test objective is to get a total tranmissibility from the whole reservoir system.
  3. Typically described as commingled (2 intervals with vertical separation) or crossflow (2 intervals with hydraulic vertical communication)

<u>Semilog Plot</u>

- The semilog plot is a plot of the pressure versus the log of time. There are typically four different semilog plots used in pressure transient and falloff testing analysis. After plotting the appropriate semilog plot, a straight line should be drawn through the points located within the equivalent radial flow portion of the plot identified from the log-log plot.

- Each plot uses a different time function depending on the length and variation of the injection rate preceding the falloff. These plots can give different results for the same test, so it is important that the appropriate plot with the correct time function is used for the analysis. Determination of the appropriate time function is discussed below.

- The slope of the semilog straight line is then used to calculate the reservoir transmissibility - kh/μ, the completion condition of the well via the skin factor - s, and also the radius of investigation - r_i of the test.

Determination of the Appropriate Time Function for the Semilog Plot
The following four different semilog plots are used in pressure transient analysis:
1. Miller Dyes Hutchinson (MDH) Plot
2. Horner Plot
3. Agarwal Equivalent Time Plot
4. Superposition Time Plot

These plots can give different results for the same test. Use of the appropriate plot with the correct time function is critical for the analysis.

- The MDH plot is a semilog plot of pressure versus Δt, where Δt is the elapsed shut-in time of the falloff.
    1. The MDH plot only applies to wells that reach psuedo-steady state during injection. Psuedo-steady state means the pressure response from the well has encountered all the boundaries around the well.
    2. The MDH plot is only applicable to injection wells with a *very* long injection period at a constant rate. This plot is not recommended for use by EPA Region 6.

- The Horner plot is a semilog plot of pressure versus $(t_p+\Delta t)/\Delta t$. The Horner plot is only used for a falloff preceded by a single constant rate injection period.
    1. The injection time, $t_p=V_p/q$ in hours, where V_p=injection volume since the last pressure equalization and q is the injection rate prior to shut-in for the falloff test. The injection volume is often taken as the cumulative injection since completion.
    2. The Horner plot can result in significant analysis error if the injection rate varies prior to the falloff.

- The Agarwal equivalent time plot is a semilog plot of the pressure versus Agarwal equivalent time, Δt_e.
    1. The Agarwal equivalent time function is similar to the Horner plot, but scales the falloff to make it look like an injectivity test.
    2. It is used when the injection period is a short, constant rate compared to the length of the falloff period.
    3. The Agarwal equivalent time is defined as: $\Delta t_e=\log(t_p\ \Delta t)/(t_p+\Delta t)$, where t_p is calculated the same as with the Horner plot.

- The superposition time function accounts for variable rate conditions preceding the falloff.
  1. It is the most rigorous of all the time functions and is usually calculated using welltest software.
  2. The use of the superposition time function requires the operator to accurately track the rate history. As a rule of thumb, at a minimum, the rate history for twice the length of the falloff test should be included in the analysis.

The determination of which time function is appropriate for the plotting the welltest on semilog and log-log plots depends on available rate information, injection period length, and software:

1. If there is not a rate history other than a single rate and cumulative injection, use a Horner time function
2. If the injection period is shorter than the falloff test and only a single rate is available, use the Agarwal equivalent time function
3. If you have a variable rate history use superposition when possible. As an alternative to superposition, use Agarwal equivalent time on the log-log plot to identify radial flow. The semilog plot can be plotted in either Horner or Agarwal time if radial flow is observed on the log-log plot.

<u>Parameter Calculations and Considerations</u>

- Transmissibility - The slope of the semilog straight line, m, is used to determine the transmissibility (kh/μ) parameter group from the following equation:

$$\frac{k \cdot h}{\mu} = \frac{162.6 \cdot q \cdot B}{m}$$

where,
q = injection rate, bpd (negative for injection)
B = formation volume factor, rvb/stb (Assumed to be 1 for formation fluid)
m = slope of the semilog straight line through the radial flow portion of the plot in psi/log cycle
k = permeability, md
h = thickness, ft (See Appendix, page A-15)
μ = viscosity, cp

- The viscosity, μ , is usually that of the formation fluid. However, if the waste plume size is massive, the radial flow portion of the test may remain within the waste plume. (See Appendix, page A-14)
  1. The waste and formation fluid viscosity values usually are similar, however, if the wastestream has a significant viscosity difference, the size of the waste plume and distance to the radial flow period should be calculated.
  2. The mobility, k/μ, differences between the fluids may be observed on the derivative curve.

- The permeability, k, can be obtained from the calculated transmissibility (kh/μ) by substituting the appropriate thickness, h, and viscosity, μ, values.

Skin Factor

- In theory, wellbore skin is treated as an infinitesimally thin sheath surrounding the wellbore, through which a pressure drop occurs due to either damage or stimulation. Industrial injection wells deal with a variety of waste streams that alter the near wellbore environment due to precipitation, fines migration, ion exchange, bacteriological processes, and other mechanisms. It is reasonable to expect that this alteration often exists as a zone surrounding the wellbore and not a skin. Therefore, at least in the case of industrial injection wells, the assumption that skin exists as a thin sheath is not always valid. This does not pose a serious problem to the correct interpretation of falloff testing except in the case of a large zone of alteration, or in the calculation of the flowing bottomhole pressure. The Region has seen instances in which large zones of alteration were suspected of being present.

- The skin factor is the measurement of the completion condition of the well. The skin factor is quantified by a positive value indicating a damaged completion and a negative value indicating a stimulated completion.
  1. The magnitude of the positive value indicating a damaged completion is dictated by the transmissibility of the formation.
  2. A negative value of -4 to -6 generally indicates a hydraulically fractured completion, whereas a negative value of -1 to -3 is typical of an acid stimulation in a sandstone reservoir.
  3. The skin factor can be used to calculate the effective wellbore radius, r_{wa} also referred to the apparent wellbore radius. (See Appendix, page A-13)
  4. The skin factor can also be used to correct the injection pressure for the effects of wellbore damage to get the actual reservoir pressure from the measured pressure.

- The skin factor is calculated from the following equation:

$$s = 1.1513\left[\frac{P_{1hr} - P_{wf}}{m} - \log\left(\frac{k \cdot t_p}{\left(t_p + 1\right)\cdot \phi \cdot \mu \cdot c_t \cdot r_w^2}\right) + 3.23\right]$$

where, s = skin factor, dimensionless

P_{1hr} = pressure intercept along the semilog straight line at a shut-in time of 1 hour, psi

P_{wf} = measured injection pressure prior to shut-in, psi

μ = appropriate viscosity at reservoir conditions, cp (See Appendix, page A-14)

m = slope of the semilog straight line, psi/cycle

k = permeability, md

ϕ = porosity, fraction

c_t = total compressibility, psi^{-1}

r_w = wellbore radius, feet

t_p = injection time, hours

Note that the term $t_p/(t_p + \Delta t)$, where Δt=1 hr, appears in the log term. This term is usually assumed to result in a negligible contribution and typically is taken as 1 for large t. However, for relatively short injection periods, as in the case of a drill stem test (DST), this term can be significant.

Radius of Investigation

- The radius of investigation, r_i, is the distance the pressure transient has moved into a formation following a rate change in a well.

- There are several equations that exist to calculate the radius of investigation. All the equations are square root equations based on cylindrical geometry, but each has its own coefficient that results in slightly different results, (See Oil and Gas Journal, Van Poollen, 1964).

- Use of the appropriate time is necessary to obtain a useful value of r_i. For a falloff time shorter than the injection period, use Agarwal equivalent time function, Δt_e, at the end of the falloff as the length of the injection period preceding the shut-in to calculate r_i.

- The following two equivalent equations for calculating r_i were taken from SPE Monograph 1, (Equation 11.2) and Well Testing by Lee (Equation 1.47), respectively:

$$r_i = \sqrt{0.00105 \frac{k \cdot t}{\phi \cdot \mu \cdot c_t}} \equiv \sqrt{\frac{k \cdot t}{948 \cdot \phi \cdot \mu \cdot c_t}}$$

Effective Wellbore Radius

- The effective wellbore radius relates the wellbore radius and skin factor to show the effects of skin on wellbore size and consequently, injectivity.

- The effective wellbore radius is calculated from the following:

$$r_{wa} = r_w e^{-s}$$

- A negative skin will result in a larger effective wellbore radius and therefore a lower injection pressure.

Reservoir Injection Pressure Corrected for Skin Effects

- The pressure correction for wellbore skin effects, ΔP_{skin}, is calculated by the following:

$$\Delta P_{skin} = 0.868 \cdot m \cdot s$$

where, m = slope of the semilog straight line, psi/cycle
s = wellbore skin, dimensionless

- The adjusted injection pressure, P_{wfa} is calculated by subtracting the ΔP_{skin} from the measured injection pressure prior to shut-in, P_{wf}. This adjusted pressure is the calculated reservoir pressure prior to shutting in the well, Δt=0, and is determined by the following:

$$P_{wfa} = P_{wf} - \Delta P_{skin}$$

- From the previous equations, it can be seen that the adjusted bottomhole pressure is directly dependent on a single point, the last injection pressure recorded prior to shut-in. Therefore, an accurate recording of this pressure prior to shut-in is important. Anything that impacts the pressure response, e.g., rate change, near the shut-in of the well should be avoided.

Determination of the Appropriate Fluid Viscosity

- If the wastestream and formation fluid have similar viscosities, this process is not necessary.

- This is only needed in cases where the mobility ratios are extreme between the wastestream, $(k/\mu)_w$, and formation fluid, $(k/\mu)_f$. Depending on when the test reaches radial flow, these cases with extreme mobility differences could cause the derivative curve to change and level to another value. Eliminating alternative geologic causes, such as a sealing fault, multiple layers, dual porosity, etc., leads to the interpretation that this change may represent the boundary of the two fluid banks.

- First assume that the pressure transients were propagating through the formation fluid during the radial flow portion of the test, and then verify if this assumption is correct. This is generally a good strategy except for a few facilities with exceptionally long injection histories, and consequently, large waste plumes. The time for the pressure transient to exit the waste front is calculated. This time is then identified on both the log-log and semilog plots. The radial flow period is then compared to this time.

- The radial distance to the waste front can then be estimated volumetrically using the following equation:

$$r_{waste\,plume} = \sqrt{\frac{0.13368 \cdot V_{waste\,injected}}{\pi \cdot h \cdot \phi}}$$

where,
$V_{waste\ injected}$ = cumulative waste injected into the completed interval, gal
$r_{waste\ plume}$ = estimated distance to waste front, ft
h = interval thickness, ft
ϕ = porosity, fraction

- The time necessary for a pressure transient to exit the waste front can be calculated using the following equation:

$$t_w = \frac{126.73 \cdot \mu_w \cdot c_t \cdot V_{waste\,injected}}{\pi \cdot k \cdot h}$$

where,
t_w= time to exit waste front, hrs
$V_{waste\ injected}$ = cumulative waste injected into the completed interval, gal
h = interval thickness, ft

k = permeability, md
μ_w = viscosity of the historic waste plume at reservoir conditions, cp
c_t = total system compressibility, psi^{-1}

- The time should be plotted on both the log-log and semilog plots to see if this time corresponds to any changes in the derivative curve or semilog pressure plot. If the time estimated to exit the waste front occurs before the start of radial flow, the assumption that the pressure transients were propagating through the reservoir fluid during the radial flow period was correct. Therefore, the viscosity of the reservoir fluid is the appropriate viscosity to use in analyzing the well test. If not, the viscosity of the historic waste plume should be used in the calculations. If the mobility ratio is extreme between the wastestream and formation fluid, adequate information should be included in the report to verify the appropriate fluid viscosity was utilized in the analysis.

Reservoir Thickness

- The thickness used for determination of the permeability should be justified by the operator. The net thickness of the defined injection interval is not always appropriate.

- The permeability value is necessary for plume modeling, but the transmissibility value, kh/μ, can be used to calculate the pressure buildup in the reservoir without specifying values for each parameter value of k, h, and μ.

- Selecting an interval thickness is dependent on several factors such as whether or not the injection interval is composed of hydraulically isolated units or a single massive unit and wellbore conditions such as the depth to wellbore fill. When hydraulically isolated sands are present, it may be helpful to define the amount of injection entering each interval by conducting a flow profile survey. Temperature logs can also be reviewed to evaluate the intervals receiving fluid. Cross-sections may provide a quick look at the continuity of the injection interval around the injection well.

- A copy of a SP/Gamma Ray well log over the injection interval, the depth to any fill, and the log and interpretation of available flow profile surveys run should be submitted with the falloff test to verify the reservoir thickness value assumed for the permeability calculation.

Use of Computer Software

- To analyze falloff tests, operators are encouraged to use well testing software. Most software has type curve matching capabilities. This feature allows the simulation of the entire falloff test results to the acquired pressure data. This type of analysis is particularly useful in the recognition of boundaries, or unusual reservoir characteristics, such as dual porosity. It should be noted that type curve matching is not considered a substitute, but is a compliment to the analysis.

- All data should be submitted electronically with a label stating the name of the facility, the well number(s), and the date of the test(s). The label or READ.Me file should include the names of all the files contained on the diskette, along with any necessary explanations of the information. The parameter units format (hh:mm:ss, hours, etc.) should be noted for the pressure file for synchronization to the submitted injection rate information. The file containing the gauge data analyzed in the report should be identified and consistent with the hard copy data included in the report. If the injection rate information for any well included in the analysis is greater than 10 entries, it should also be included electronically.

Common Sense Check

- After analyzing any test, always look at the results to see if they "make sense" based on the type of formation tested, known geology, previous test results, etc. Operators are ultimately responsible for conducting an analyzable test and the data submitted to the regulatory agency.

- If boundary conditions are observed on the test, review cross-sections or structure maps to confirm if the presence of a boundary is feasible. If so, the boundary should be considered in the AOR pressure buildup evaluation for the well.

- Anomalous data responses may be observed on the falloff test analysis. These data anomalies should be evaluated and explained. The analyst should investigate physical causes in addition to potential reservoir responses. These may include those relating to the well equipment, such as a leaking valve, or a channel, and those relating to the data acquisition hardware such as a faulty gauge. An anomalous response can often be traced to a brief, but significant rate change in either the test well or an offset well.

- Anomalous data trends have also been caused by such things as ambient temperature changes in surface gauges or a faulty pressure gauge. Explanations for data trends may be facilitated through an examination of the backup pressure gauge data, or the temperature data. It is often helpful to qualitatively examine the pressure and/or temperature channels from both gauges. The pressure data should overlay during the falloff after being corrected for the difference in gauge depths. On occasion, abrupt temperature changes can be seen to correspond to trends in the pressure data. Although the source of the temperature changes may remain unexplainable, the apparent correlation of the temperature anomaly to the pressure anomaly can be sufficient reason to question the validity of the test and eliminate it from further analysis.

- The data that is obtained from pressure transient testing should not collect dust, but be compared to petition or permit parameters. Test derived transmissibilities and static pressures can confirm compliance with no migration and non-endangerment (AOR) conditions.